

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND)	DOCKET UE-140762
TRANSPORTATION COMMISSION,)	<i>(Consolidated)</i>
)	
Complainant,)	ORDER 08
)	
v.)	FINAL ORDER REJECTING
)	TARIFF SHEETS;
PACIFIC POWER & LIGHT)	RESOLVING CONTESTED
COMPANY, a Division of PacifiCorp,)	ISSUES; AUTHORIZING
)	AND REQUIRING
Respondent.)	COMPLIANCE FILINGS;
)	
.....)	
In the Matter of)	DOCKET UE-140617
)	<i>(Consolidated)</i>
PACIFIC POWER & LIGHT)	
COMPANY)	GRANTING, IN PART,
)	RECOVERY OF DEFERRED
Petition for an Order Approving)	COSTS;
Deferral of the Washington-Allocated)	
Revenue Requirement Associated with)	
the Merwin Fish Collector.)	
.....)	
In the Matter of)	DOCKET UE-131384
)	<i>(Consolidated)</i>
PACIFIC POWER & LIGHT)	
COMPANY)	DENYING PETITION FOR
)	ACCOUNTING ORDER;
Petition for an Order Approving)	
Deferral of Costs Related to Colstrip)	
Outage.)	
.....)	
In the Matter of)	DOCKET UE-140094
)	<i>(Consolidated)</i>
PACIFIC POWER & LIGHT)	
COMPANY)	DENYING PETITION FOR
)	ACCOUNTING ORDER
Petition for an Order Approving)	
Deferral of Costs Related to Declining)	
Hydro Generation.)	
.....)	

Synopsis: The Commission rejects revised tariff sheets Pacific Power & Light Company (Pacific Power or Company) filed on May 1, 2014, that would have increased rates by 8.5 percent, raising \$27.2 million in additional revenue for the Company, if approved by the Commission. The Commission, considering the full record, authorizes and requires Pacific Power to file revised tariff sheets stating rates that will recover \$9.6 million in additional revenue, resulting in a 3.0 percent increase in rates that the Commission finds to be reasonable.

The Commission rejects Pacific Power's request that it revisit the Company's recently rejected proposal to revise the West Control Area inter-jurisdictional cost allocation methodology applicable to the cost of Qualifying Facilities under the Public Utilities Regulatory Policies Act (PURPA)¹. In addition, the Commission exercises its discretion to not revisit the interrelated questions of what the rate of return on equity component and equity ratio should be in Pacific Power's capital structure. The Commission heard and decided these issues just five months prior to Pacific Power filing this case and shortly after the Company appealed these decisions to Division II of the Washington State Court of Appeals. The Commission will not entertain the Company's proposals to rehear them in this proceeding.

The Commission resolves several contested pro forma expense adjustments, including adjustments related to the Company's net power costs. In connection with power cost recovery going forward, the Commission requires Pacific Power, following further proceedings, to file appropriate tariff sheets to implement a properly designed Power Cost Adjustment Mechanism (PCAM) that will protect the Company from extra-normal power cost variability while giving Pacific Power adequate incentive to manage carefully its full power portfolio.

The Commission approves various additions to rate base, including the known and measurable pro forma costs of certain facilities that are now used and useful, albeit with post-test period in-service dates.

The rates determined in this Order to be fair, just, reasonable, and sufficient are based on a capital structure of 49.10 percent equity, 50.69 percent long-term debt, 0.19 percent short-term debt, and 0.02 percent preferred stock, with a 9.5 percent

¹ Pub.L. 95–617, 92 Stat. 3117 (enacted November 9, 1978).

return on equity, a 5.19 percent cost of long-term debt, a 1.73 percent cost of short-term debt, and a 6.75 cost of preferred stock. This results in an overall rate of return of 7.30 percent.

The Commission rejects Pacific Power's and Staff's respective recommendations for significant increases in the residential customer basic charge and Staff's related recommendation for the addition of a third inverted block rate that would apply to higher levels of consumption by residential customers. The Commission restates its preference for a decoupling mechanism to address issues of fixed cost recovery while promoting conservation investment and encouraging, or at least not impeding, the development of distributed generation.

Finally, the Commission approves increased funding for PacifiCorp's Low Income Bill Assistance Program consistent with the requirements of the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012. We encourage continued efforts by the Company, Staff, the Energy Project, and others who recognize the importance of ensuring that low-income customers have access to the vital services Pacific Power provides, to find innovative means to provide it.

In the consolidated dockets, the Commission grants Pacific Power's proposals to refund deferred over-recoveries of depreciation expense, and to recover deferred Operating & Maintenance expense and depreciation expense (i.e., return of investment) for the Merwin Fish Collector Project (Merwin Project), but denies recovery of deferred interest (i.e., return on the Merwin Project investment). The Company will recover return on the Merwin Project investment in rate base going forward, just as in the case of any other post-test period plant addition.

The Commission denies Pacific Power's petitions for accounting orders allowing deferred treatment of replacement power costs in Docket UE-131384 (Colstrip Outage) and Docket UE-140094 (Hydropower Deferral). Neither request demonstrates extraordinary costs that might support such treatment. We prefer to address volatility in power costs through a properly designed Power Cost Adjustment Mechanism (PCAM), which we require the Company to file in this Order, rather than continued filing of petitions to defer accounting treatment of power costs.

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SUMMARY

- 1 **PROCEEDING:** Pacific Power & Light Company (Pacific Power), an operating division of PacifiCorp,² filed this general rate case (GRC) proceeding with the Washington Utilities and Transportation Commission (Commission) in Docket UE-140762 on May 1, 2014, seeking to recover additional revenue of approximately \$27.2 million.³ The Company also requests deferral accounting treatment and amortization over one year of \$4.9 million related to replacement power costs arising from an outage at Unit 4 of the Colstrip generating plant (Docket UE-131384) and anticipated low hydropower conditions during 2014 (Docket UE-140094). On April 14, 2014, PacifiCorp filed with the Commission in Docket UE-140617 an accounting petition seeking authorization to defer approximately \$1.7 million per year (\$142,000 per month) associated with the Merwin Fish Collector Project (Merwin Project). The Commission granted the accounting petition on May 29, 2014.⁴ Pacific Power now requests to recover in rates the deferral balance for the Merwin Project. The Commission consolidated these four dockets.
- 2 Following public comment hearings in Yakima on September 25, 2014, and in Walla Walla on September 26, 2014, and evidentiary hearings in Olympia on December 16-19, 2014, the parties filed Initial Briefs and Reply Briefs on January 22 and February 3, 2015, respectively. This Final Order resolves all disputed issues in these proceedings.

² PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly-formed Oregon corporation that retained the PacifiCorp name. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name of its operating division, Rocky Mountain Power, and to customers in Oregon, Washington and California under the trade name of its operating division, Pacific Power. PacifiCorp's electric generation, commercial and trading, and coal mining functions are operated under the trade name of its third principal operating division PacifiCorp Energy. PacifiCorp is a wholly-owned subsidiary of Berkshire Hathaway Energy which, in turn, is wholly owned by its affiliate, Berkshire Hathaway.

³ Pacific Power increased its revenue request in its rebuttal testimony filed on November 14, 2014, to \$31.9 million, “driven primarily by the Company’s net power cost update” and based on it requested 10 percent return on equity. Dalley, Exh. No. RBD-3T at 1:15-17. By the conclusion of the evidentiary hearing, Pacific Power’s request was at \$30,398,178.

⁴ *WUTC v. Pacific Power & Light Co.*, Docket UE-140617, Order 01 (May 29, 2014).

- 3 **PARTY REPRESENTATIVES:** Katherine A. McDowell and Adam Lowney, McDowell Rackner & Gibson PC, Portland, Oregon, and Sarah Wallace, Assistant General Counsel, Pacific Power, represent the Company. Patrick J. Oshie, Brett P. Shearer, and Jennifer Cameron-Rulkowski, Assistant Attorneys General, Olympia, represent the Commission’s Regulatory Staff (Staff).⁵ Simon J. ffitch, Senior Assistant Attorney General, Seattle, represents the Public Counsel Section of the Washington Office of Attorney General (Public Counsel).
- 4 Melinda J. Davison and Jesse Cowell, Davison Van Cleve, Portland, Oregon, represent the Boise White Paper, L.L.C. (Boise White Paper). Brad M. Purdy, attorney at law, Boise, Idaho, represents the Energy Project.⁶ Samuel L. Roberts, Hutchinson, Cox, Coons, Orr & Sherlock PC, Eugene, Oregon, represents Walmart Stores, Inc. (Walmart). Joseph F. Wiedman, Keyes, Fox & Wiedman, Oakland, California, represents The Alliance for Solar Choice.
- 5 **COMMISSION DETERMINATIONS:** The Commission, on May 14, 2014, suspended and set for hearing the rates Pacific Power originally proposed in its general rate case (GRC) filing, and the petitions for deferral accounting and recovery of replacement power costs associated with the Colstrip outage and hydropower conditions during 2014. On May 29, 2014, the Commission consolidated into the GRC the Merwin deferral matter. Based on the record of this proceeding we find that neither the Company’s as-filed rates, nor the revised rate request Pacific Power made through its rebuttal filing and at the conclusion of the advocacy phase, are fair, just and reasonable. We reject Pacific Power’s accounting petition and proposed recovery of deferred costs in Docket UE-140094 (low hydropower production), reject the Company’s accounting petition and proposed recovery of deferred power costs in

⁵ In formal proceedings, such as this, the Commission’s regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners’ policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

⁶ The Columbia Rural Electric Association (CREA), represented by Irion Sanger, Davison Van Cleve, Portland, Oregon was granted leave to intervene in this proceeding under the “participation in the public interest” standard in WAC 480-07-355(3) in connection with a single issue that later was withdrawn from the case. In its order granting Pacific Power leave to withdraw the issue, the Commission dismissed CREA as an intervenor as provided in WAC 480-07-355(4).

Docket UE-131384 (Colstrip outage), and reject in part the Company's proposed recovery of deferred costs in Docket UE-140617 (Merwin Project).

- 6 We find that Pacific Power requires a modest increase in revenue to ensure its prospective rates are sufficient. We specifically find a revenue deficiency of \$9,568,464 for Pacific Power's electric service provided in Washington. The updated net power costs determined in this proceeding will establish the initial baseline for a Power Cost Adjustment Mechanism (PCAM) that we require Pacific Power to implement by filing appropriate tariff sheets in compliance with this Order. The Company's new rates, including updated net power costs, will be effective no earlier than April 1, 2015.
- 7 We decline to adjust the equity ratio and rate of return on equity included in the Company's capital structure. We decided these issues only five months before Pacific Power filed this case and will exercise our discretion not to rehear or decide them in this docket.⁷ We also will not rehear the question whether we should change the West Control Area situs allocation methodology for the costs of Qualifying Facilities under PURPA. Not only did we decide these issues within months prior to Pacific Power's filing of this GRC, they also are the subjects of the Company's appeal now pending in Division II of the Washington Court of Appeals. We do not wish to risk disrupting the Court's well-ordered consideration of the matters before it.
- 8 Washington relies on a hybrid test year approach to ratemaking. Although the Commission starts with a historic test year, we allow *pro forma* adjustments to rate base and expenses that often extend beyond what is known and measurable as of the end of the test year. The Commission, in addition, sets the largest single utility expense, net power costs, on a forward basis using data and cost projections that are as nearly contemporaneous as practicable with the effective date of new rates. The Commission, albeit forward looking in its approach, rejects Pacific Power's efforts to have us determine rates using methods that push too far in the direction of regulatory policies and practices suitable to states that use a future test year approach to ratemaking instead of a hybrid test year approach.
- 9 Finally, in prior general rate cases the Commission has requested the Company to take advantage of regulatory mechanisms available in Washington that are designed to enhance the ability of utilities to effect timely recovery of their authorized revenue

⁷ See RCW 80.04.220.

requirements. Pacific Power has refused to do so. A Power Cost Adjustment Mechanism (PCAM) designed in accordance with the regulatory policy guidance this Commission has given Pacific Power in prior cases is long overdue. We authorize and require Pacific Power to implement a properly designed PCAM in compliance with this Order. The Commission will conduct brief additional proceedings to determine the details required for such a mechanism.

- 10 In terms of fixed cost recovery, the Commission has expressed and demonstrated its preference for the use of decoupling.⁸ The Commission has approved such mechanisms for several companies. Pacific Power has not yet come forward with a fully developed decoupling proposal. In this Order we invite the Company, Staff, and other interested parties to put such a proposal before the Commission in Pacific Power's next general rate case.

MEMORANDUM

I. Background and Procedural History

- 11 On May 1, 2014, Pacific Power filed revised tariff sheets with the Commission to increase rates and charges for electric service provided to customers in the state of Washington. The Company requested an electric rate increase of \$27.2 million, or 8.5 percent. In addition, the Company sought deferral accounting authority and amortization over one year of \$4.9 million, or 1.5 percent, related to replacement power to cover an outage at Unit 4 of the Colstrip generating plant (Docket UE-131384) and low hydropower conditions (Docket UE-140094). The Company proposes to recover these deferred costs via a separate tariff rider, Schedule 92.
- 12 On April 14, 2014, the Company filed with the Commission in Docket UE-140617 a new tariff - Schedule 90 entitled "Hydro Investment Adjustment." The purpose of this schedule was to recover costs associated with the Merwin Fish Collector project (Merwin Project). As an alternative to allowing the separate tariff rider to go into effect by operation of law, Pacific Power included in its filing an accounting petition for authorization to defer the revenue requirement of approximately \$1.7 million per year (\$142,000 per month) associated with the Merwin Project.

⁸ See *In re WUTC Investigation into Energy Conservation Incentives*, Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, including Decoupling, To Encourage Utilities To Meet or Exceed Their Conservation Targets at (Nov. 4, 2010) (Decoupling Policy Statement).

- 13 In Order 01 in Docket UE-140762, entered on May 14, 2014, the Commission suspended the tariff sheets Pacific Power filed on May 1, 2014. On May 29, 2014, the Commission entered Order 03 in Docket UE-140762 and Order 01 in Docket UE-140617, consolidating the dockets, suspending the tariff sheets filed on April 14, 2014, and authorizing the Merwin Project deferral. In light of the Commission's approval of the alternative deferred accounting treatment for the Merwin Project costs, the Company withdrew its proposed tariff in Docket UE-140617, on May 30, 2014. Pacific Power now proposes recovery of \$1.7 million in deferred costs related to the Merwin Project over one year in Schedule 92. This brings the total request for recovery via Schedule 92 to \$6.6 million.
- 14 The Commission convened a prehearing conference in the consolidated proceedings at Olympia, on May 30, 2014. The Commission held public comment hearings in Yakima on September 25, 2014, and in Walla Walla on September 26, 2014. On various dates established in its procedural schedule, the Commission accepted prefiled testimony and exhibits from the Company, the Staff, and other parties. The Commission held evidentiary hearings in Olympia on December 16-19, 2014, to receive evidence from the parties and to allow them an opportunity to conduct cross-examination of witnesses who prefiled testimony. These hearings also gave the Commission an opportunity to conduct inquiry from the bench.
- 15 During the public comment hearings, the Commission received into the record oral comments and exhibits from 20 members of the public. The Commission also accepted numerous written comments from members of the public.⁹ The final transcript in this proceeding includes 663 pages and reflects the admission of prefiled testimony and exhibits sponsored by 30 witnesses. The documentary record includes 377 exhibits.
- 16 The parties filed their Initial Briefs on January 22, 2015, and Reply Briefs on February 3, 2015. The final record, including public comment and detailed evidence concerning Pacific Power's revenue requirements and other issues, was closed on February 18, 2015, following receipt of several responses to Commission bench requests made during and after the hearing. We have considered the parties' arguments and reviewed the full record. Our discussion and determination of the issues follows below.

⁹ These comments are identified in the formal record as Exhibit B-1.

II. Ratemaking Authority and Practice

17 The Commission’s general powers and duties set forth in RCW 80.01.040 include its responsibility to:

Regulate in the public interest, as provided by the public service laws, the rates, services, facilities, and practices of all persons engaging within this state in the business of supplying any utility service or commodity to the public for compensation.¹⁰

When a utility subject to the Commission’s jurisdiction, such as Pacific Power, files tariff sheets that would effect a change in the rates, terms, or conditions of its service to customers in Washington that is a “general rate proceeding” under WAC 480-07-505. In such cases, the Commission typically exercises its authority under RCW 80.04.130 (1) to suspend the effectiveness of the filing for up to 10 months and set the matter for hearing.¹¹

18 The Commission’s responsibility in general rate case proceedings is to determine an appropriate balance between the needs of the public to have safe and reliable electric services at reasonable rates, and the financial ability of the utility to provide such services on an ongoing basis. In statutory parlance, whenever the Commission finds, after a hearing, that a utilities rates are “unjust, unreasonable, unjustly discriminatory or unduly preferential,” or that its rates “are insufficient to yield a reasonable compensation” to the utility, the Commission must “determine the just, reasonable, or sufficient rates” to be effective prospectively.¹² Table 1 illustrates that the parties in this proceeding hold very different ideas of what amount of revenue increase, or decrease, will produce rates that strike this balance.

¹⁰ RCW 80.01.040 (3).

¹¹ *See supra* ¶ 11.

¹² RCW 80.28.020.

TABLE 1				
Proposed Total Adjustments to Annual Revenue Requirement				
	As-Filed	Response	Rebuttal/Cross	Per Briefs
PP&L	\$27,201,266 (8.5%)		\$31,938,957 (9.9%)	\$30,398,178 (9.5%)
Staff		\$7,740,733 (2.41%)		\$7,955,874 (2.47%)
Public Counsel		\$1,126,556 (0.35%)		\$1,126,556 (0.35%)
Boise White Paper		\$(2,736,141) (0.85%)		\$3,344,138 (1.04%)

The range of possible outcomes most likely encompasses a somewhat narrower range of reasonable outcomes. We must determine solely on the record of this proceeding the reasonable range and what revenue requirement within the reasonable range results in rates that are just, reasonable, and sufficient.¹³

19 Although “not bound to the use of any single formula or combination of formulae in determining rates”¹⁴ we must find on the basis of the record three things:

¹³ The seminal cases establishing the legal principles for utility rate regulation that have continued to guide ratemaking practice for 75 years refer to the “just and reasonable standard,” leaving “sufficient” as an implied constitutional condition for just and reasonable rates from the utility company’s perspective. Thus, in *Fed. Power Comm’n v. Hope Nat. Gas Co.*, 320 U.S. 591, 602-03 (1944), the Supreme Court stated that there are various “permissible ways in which any rate base on which the return is computed might be arrived at,” and it is constitutionally sound so long as the “result reached” by the regulator is just and reasonable from the company viewpoint. See also *Fed. Power Comm’n v. Nat. Gas Pipeline Co.*, 315 U.S. 575, 586 (1942) (“[T]he just and reasonable standard . . . coincides with the applicable constitutional standards.” The Court reaffirmed the “teachings of Hope” in *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989).

¹⁴ *Hope*, 320 U.S. at 602. Expanding on this point, the Court said:

Under the statutory standard of ‘just and reasonable’ it is the result reached not the method employed which is controlling. It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important.

Id. This language, embodying the familiar “end result” test, is universally recognized as an important guiding principle in utility ratemaking throughout the United States. In a later case, the

- What levels of prudently incurred expenses the Company will experience during the rate year.¹⁵
- The amount of the Company’s “rate base.”¹⁶
- An appropriate rate of return on that rate base.

The Washington Supreme Court explained this rate-making formula as follows:

In order to control aggregate revenue and set maximum rates, regulatory commissions such as the WUTC commonly use and apply the following equation:

$$R = O + B(r)$$

Supreme Court embraced the end result test and recognized a “zone of reasonableness” within which rates approved by a regulatory authority may not be set aside. *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 767 (1968). The Washington Supreme Court, more recently yet, made clear the applicability of these principles in cases before this Commission:

While modernly a reviewing court’s role in this State is delineated by the administrative procedure act . . . *Hope Natural Gas* and *Permian Basin* continue to provide guidance in the judicial review of rate cases; and it remains the law that courts are not at liberty to substitute their judgment for that of the Commission.

People’s Org. for Wash. Energy Res. v. Utils. & Transp. Comm’n, 104 Wn. 2d 798, 812 (1985) (*POWER*).

¹⁵ The rate year begins on the date the Commission authorizes or allows new rates to become effective. This may be as early as 30 days after a company files revised tariff sheets. *See* RCW 80.04. Typically, however, when a company files a general rate case, the as-filed tariff sheets are suspended for a period of up to 10 months after their stated effective date and the benchmark effective date for revised rates to become effective is the day after the last day of the statutory suspension period. In this case, the benchmark effective date is April 1, 2015. Thus, the anticipated rate year in this case is April 1, 2015, through March 31, 2016.

¹⁶ Reduced to a simple definition, rate base is the Commission-approved level of PSE’s investment in facilities plus the cash, or “working capital” supplied by investors that is used to fund the Company’s day-to-day operations. The Commission follows the original cost less depreciation method when determining the value of a utility’s property that is used and useful in providing service to customers. *POWER*, 104 Wn.2d at 828.

In this equation,

R is the utility's allowed revenue requirement;

O is its operating expenses;

B is its rate base; and

r is the rate of return allowed on its rate base.

Although regulatory agencies, courts and text writers may vary these symbols and notations somewhat, this basic equation is the one which has evolved over the past century of public utility regulation in this country and is the one commonly accepted and used.¹⁷

The sum of the two figures – expenses and return on rate base – constitutes the Company's revenue requirement that we approve for recovery in rates. This basic formula is a simple expression of a complex, highly technical, and formal process.¹⁸ The goal for the Commission in conducting this process is to reach an end result that allows the Company to recover the costs of its investments in infrastructure, repay its lenders, and provide an opportunity for the Company to earn a reasonable return, some of which may be distributed to its equity investors in the form of dividends.¹⁹ Thus, we determine just and reasonable rates that are safely above the constitutional minimum and that afford the utility recovery of its operating expenses and both the return of its prudent investments through depreciation expense and an opportunity for its investors to earn a fair return on their investments that are used and useful for providing utility services.

20 States are free, within broad limits, to decide what ratemaking methodology best meets their needs in balancing the interests of the utility and the public it serves.²⁰ Washington ratemaking practice is based on a hybrid test year that uses historic data

¹⁷ *Id.* at 809.

¹⁸ *See id.* at 807-09 (describing ratemaking principles and process).

¹⁹ Regulatory agencies need not, and do not guarantee that a utility will recover its authorized return. "A regulated [utility] has no constitutional right to a profit" and regulation does not even ensure that the regulated company will produce net revenues. *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1180-81 (D.C. Cir. 1987) (*en banc*); *see also Nat. Gas Pipeline Co.*, 315 U.S. at 590. Indeed, a rate is not necessarily unlawful even if it results in the company operating at a loss so long as it gave the company the opportunity to operate at a profit when approved.

²⁰ *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 315-16 (1989).

as a starting point for analysis. While this distinguishes Washington practice from the future test year approach used to set Pacific Power's rates in Utah, Oregon, and California, in point of fact, Washington practice is quite forward looking. Although we are often recognized as a historic test year state, it is more accurate to say that the Commission relies on a "modified" or "hybrid" test year.²¹ The Commission, for example:

- Approves pro-forma adjustments to test-year costs when the adjustments are adequately supported.
- Allows calculation of base power costs based on costs projected for the rate year based on data contemporaneous with the end of a general rate case (*i.e.*, at the beginning of the rate year).
- Accepts filings for updates to power costs "between rate cases." For PSE, it allows for expedited power-cost-only rate cases (PCORCs) that adjust rates to reflect addition of new power resources, or fuels costs, without requiring a comprehensive rate proceeding.
- Allows new generation plant in rate base even when the new facilities are placed in service subsequent to the end of the test period.
- Has approved end-of-period rate base when this is shown to be appropriate.
- Has allowed CWIP (Construction Work in Progress) in rate base.
- Has approved hypothetical capital structures to improve a utility's weakened financial condition.

²¹ With these principles in mind, we turn in the sections following below to consideration of the contested issues, starting with proposed *pro forma* adjustments. We resolve first disputes concerning general wages and retirement benefits, insurance expense, and the Company's proposal to apply an escalation factor to Operating & Maintenance (O&M) expenses apart from labor- and power-related O&M expenses.

²¹ See Lowry, Mark Newton, Hovde, David Getachew, Lullit' Makos, Matt, Edison Electric Institute, *Forward Test Years for U.S. Electric Utilities*, August 2010.

- 22 Pacific Power's net power costs are a principal driver of its request for increased revenue with power cost issues accounting for nearly 46 percent of the total amount of the increase the Company proposes. This includes increases in updated net power costs reflected in the Company's rebuttal testimony, which are driven principally by post-test period increases in the costs of coal to fuel the Company's Colstrip and Jim Bridger power plants. These updates added an additional \$5.4 million to Pacific Power's overall revenue request.²²
- 23 In the context of this discussion, we take up Staff's proposed Power Cost Adjustment Mechanism (PCAM) and Pacific Power's proposed Renewable Resource Tracking Mechanism (RRTM). Once we determine the "O" (*i.e.*, operating expense) and "B" (*i.e.*, rate base) factors in our ratemaking equation, we complete the revenue requirement portion of our discussion with determination of the Company's cost of capital, the "r" or rate of return that is multiplied by the rate base in the basic rate equation.
- 24 To determine "r", we develop a weighted cost of capital for the Company based on a capital structure that balances safety and economy. Capital structure, and particularly the equity ratio and cost of equity, materially impacts the price customers pay for service. Due to the relative difference between the higher cost of equity and the lower cost of debt, a capital structure with relatively more debt and less equity may result in a lower overall cost of capital.²³ This results in lower rates for customers. This is commonly referred to as "economy." On the other hand, a capital structure with relatively more equity and less debt may result in a higher overall cost of capital and higher rates for customers, but enhanced financial integrity. This is commonly referred to as "safety."²⁴

²² Duvall, Exh. No. GND-4T at 8:5-9.

²³ The use of equity versus debt capital is also significant because of the impact of federal income taxes in the determination of a utility's revenue requirement. The additional revenue necessary to pay a higher return on equity must be supported by additional revenue from customers to pay Federal income taxes. On the other hand, when financing with debt the utility can deduct its interest expense resulting in a reduction in the utility's costs and revenue requirement, benefiting both customers and the utility.

²⁴ This simplified relationship assumes that the cost of equity does not vary with the equity ratio. In fact, the cost of equity may decline as the equity ratio increases because financial risk declines. See 1 Leonard Saul Goodman, *The Process of Ratemaking* 642-43 (1998).

- 25 Taking the last step to determine the specific base rates various types of customers will pay, we address Pacific Power's cost of service study, rate spread and rate design. In doing so, we establish how Pacific Power's costs will be allocated to different classes of customers, such as residential, commercial and industrial, and the means by which those costs will be recovered from each customer class in base rates and rates tied to levels of use. In this case, the Company proposes, among other things, to recover significant additional fixed costs in basic charges resulting in a nearly 80 percent increase to the residential basic charge. Staff also proposes a large increase to this charge, and proposes changes to the Company's residential volumetric block rates.
- 26 We address, too, the Company's programs that are designed to assist low-income customers that Pacific Power serves in Washington. The Company proposes to increase the number of participants, to increase the participant benefit by two times whatever residential rate increase is approved, and to reduce the monthly customer charge to qualifying customers. These proposals are consistent with a currently effective five-year plan the Commission approved previously.
- 27 Finally, we consider four related matters, three of which were initiated in separate dockets that are now consolidated into this general rate proceeding. These include two proposals by Pacific Power to recover deferred power costs (*i.e.*, costs attributed to an outage at the Colstrip power plant in Docket UE-131384, and to low-hydro conditions projected for 2014 in Docket UE-140094) and the Merwin Project deferral (*i.e.*, Docket UE-140617). The fourth matter concerns a deferral of the difference between depreciation rates approved in Docket UE-130052 and the depreciation rates reflected in the Company's 2013 GRC in Docket UE-130043.²⁵ It is appropriate to consider these matters separately in light of Pacific Power's proposed use of deferred accounting for the power costs and a separate tariff rider (*i.e.*, Schedule 92) to amortize fully any allowed costs over one year.

²⁵ The Commission, in Docket UE-132350, approved deferral of the resulting reduction in depreciation expense.

III. Discussion and Decisions

A. Introduction

28 This is Pacific Power's ninth general rate case in Washington since 2003.²⁶ But for
one case, all have resulted in rate increases for the Company.²⁷

29 The Commission entered its Final Order in Docket UE-130043, the Company's most
recently completed general rate case, on December 4, 2013.²⁸ In that order the
Commission:

- Authorized rates that would provide the Company an opportunity to recover an additional \$16.7 million in revenue during the rate year, relative to its previously authorized rates.
- Rejected Pacific Power's proposed revisions to the West Control Area inter-jurisdictional cost allocation methodology in effect since being initially authorized in June 2007, including the Company's proposal to change the situs allocation of the cost of Qualifying Facilities (QFs) under the Public Utilities Regulatory Policies Act (PURPA).²⁹

²⁶ The prior dockets are UE-032065 (2003/2004), UE-050684 (2005/2006), UE-061546 (2006/2007), UE-080220 (2008), UE-090205 (2009), UE-100749 (2010/2011), UE-111190 (2011/2012), and UE-130043 (2013/2014).

²⁷ The Commission rejected the Company's 2005 tariff filing. *Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-050684, Order 04 (April 17, 2006). The Commission's order in Docket UE-050684 is significant in the context of this case because it rejected the use of the Revised Protocol inter-jurisdictional cost allocation methodology in this state, rejected a decoupling proposal by the Company and Natural Resource Defense Council because it lacked necessary operational details and was otherwise insufficiently developed, and rejected the Company's proposed Power Cost Adjustment Mechanism because it failed to focus on short-term costs subject to market volatility or other extraordinary events beyond the Company's control, included costs for new generation, and failed to balance adequately through the use of dead bands and sharing bands the shared risks and benefits borne by shareholders and ratepayers.

²⁸ *Utilities & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-130043, Order 05 (December 4, 2013).

²⁹ Pub.L. 95-617, 92 Stat. 3117 (enacted November 9, 1978).

- Approved Pacific Power’s use of End of Period (EOP) rate base in lieu of a long and still preferred approach that uses the average of monthly averages (AMA) to determine rate base.
- Approved various additions to rate base, including the *pro forma* costs of certain production related facilities with post-test period in-service dates as late as 11 months after the end of the test year.
- Approved a capital structure including 49.10 percent equity, 50.62 percent debt, and 0.28 percent preferred stock, with a 9.5 percent return on equity, a 5.29 percent cost of debt, and a 5.43 cost of preferred stock, resulting in an overall rate of return of 7.36 percent.
- Rejected the Company’s proposed PCAM largely because the proposed mechanism was not designed in accordance with clear, prior direction from the Commission concerning the required elements for a PCAM.

Pacific Power filed a petition for judicial review that is now pending before Division II of the Washington state Court of Appeals.³⁰ The Company’s appeal challenges the Commission’s determination of two issues in Docket UE-130043:

- The decision to continue using the situs allocation methodology for QF costs as originally proposed by Pacific Power in 2006 and adopted by the Commission in 2007.³¹
- The decision to continue using a hypothetical capital structure the Commission has left unchanged through several Pacific Power GRCs, again finding it to balance safety and economy more appropriately than would Pacific Power’s proposed use of its parent corporation’s “actual” capital structure.³²

³⁰*PacifiCorp d/b/a Pacific Power & Light Company v. Washington Utilities and Transportation Commission, Public Counsel Division of the Washington State Office of the Attorney General and, Packaging Corporation of America f/k/a Boise White Paper, L.L.C.*, No. 46009-2-II.

³¹ *See Utilities & Transp. Comm’n v. PacifiCorp d/b/a Pacific Power & Light*, Dockets UE-061546 and UE-060817 (consolidated), Order 08 ¶¶ 43-58, (June 21, 2007)

³² Neither Pacific Power nor its parent, PacifiCorp, are publicly listed or traded on the stock exchanges. It thus is something of a stretch to conceive of either corporation having an “actual” capital structure. PacifiCorp’s capital structure is controlled entirely by its owner, Berkshire

30 Despite the pendency of its appeal of these two, highly significant issues, Pacific Power nevertheless filed this case on May 1, 2014, only five months after the Commission's Final Order in Docket UE-130043. In this filing, the Company makes the same arguments rejected by the Commission in the prior case, and again asks us to abandon the situs allocation methodology for QF costs and urges adjustment of the Company's capital structure balance between safety and economy in favor of Pacific Power by using PacifiCorp's "actual" capital structure.

B. *Pro Forma* Expense Adjustments

1. General Wage Increase - *Pro Forma* Expense and Pension Expense (Adjustment 4.3)

31 Pacific Power proposes to include in Washington rates a post-test year wage increase, "using known and measurable increases that have occurred or are expected to occur through March 2016."³³ The Company also proposes to apply the adjusted wage levels to its average full-time-equivalent (FTE) employee levels during the historical test year, with no post-test year adjustment, to determine labor expenses and to include in rates pension and other post-employment benefit (OPEB) expenses.³⁴

32 Public Counsel argues that the Company's post-test year wage increase proposal, extending "27 months beyond the end of the test-period," is essentially equivalent to the use of a future test period and recommends limiting the post-test year wage increases to those increases in effect by December 31, 2014.³⁵ Public Counsel argues in addition that the Company's post-test year FTE count should be adjusted to reflect a continuing trend of reduced FTEs over several years and through the pendency of the hearing.

Hathaway Energy, presumably to benefit BHE. This fact is evidenced in this case by Mr. Dalley's and Mr. Williams' testimony that PacifiCorp, after retaining 100 percent of its earnings since the time of its acquisition by BHE, recently began providing significant dividends up to BHE. While retaining earnings and other practices have inflated the level of equity on PacifiCorp's books since the time it was acquired by BHE, dividend payments will reduce the amount of equity on the Company's books. According to Mr. Williams, the corporate plan is to reduce the equity share at PacifiCorp to "about 50 percent." *See* TR. 326:24-328:7.

³³ Pacific Power Initial Brief ¶ 129.

³⁴ *Id.*

³⁵ Public Counsel Initial Brief ¶¶ 54-55; Ramas, Exh. No. DMR-1CTr at 20:20-22.

- 33 Pacific Power argues that its “proposal is consistent with Commission precedent approving similar *pro forma* adjustments for the Company’s wage and salary expenses” citing the Commission’s final order in the Company’s 2010/2011 general rate case.³⁶ In Docket UE-100749, however, the Company’s proposed *pro forma* adjustment to the test year ended December 31, 2009, was based on actual changes 12 months out, through December 31, 2010, not 27 months. Union labor cost increases were adjusted using contract agreements whereas non-union and exempt employee adjustments were based on actual labor cost increases effective January 2009 and 2010.³⁷ By the time of the hearing, in late January 2011, these costs were fully known and measurable and, indeed, there was no opposition argument to the level of the *pro forma* wage increases.³⁸ The parties’ opposition was based on their argument that the adjustment “should be disallowed because the Company did not consider all relevant factors including whether there are corresponding offsets to the wage increases.”³⁹
- 34 Public Counsel acknowledges that the Commission has allowed post-test year salary and wage increases as *pro forma* adjustments to test year costs, if they are known and measurable and occur within 12 months after the end of the test year.⁴⁰ Public Counsel argues that “this approach is more than reasonable, and should be adhered to again in this case” which would limit the *pro forma* adjustment to wages to known and measurable costs through December 31, 2014.⁴¹
- 35 Public Counsel argues in addition that the Company’s proposal essentially is to base wage and salary levels on a future test year for the 12 months ending March 31, 2016, which creates a distortion of the alignment between revenue, investment, and expense, violating the matching principle. Public Counsel contends that it is “particularly unfair to include costs from such a distant future period, given the

³⁶ Pacific Power Initial Brief ¶ 130 (citing *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶¶ 226-235 (Mar. 24, 2011)).

³⁷ *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 226 (Mar. 24, 2011).

³⁸ *See Id.* ¶ 228.

³⁹ *Id.* ¶ 227.

⁴⁰ Public Counsel Initial Brief ¶ 55 (citing Ramas, Exh. No. DMR-1CTr at 20:8-18.)

⁴¹ *Id.*

evidence in the record that PacifiCorp's employee count has been declining for the past 3½ years.”⁴²

36 Elaborating on this last point, Public Counsel states that while Pacific Power's adjusted test year labor costs are based on the average number of employees employed by the Company during the test year ending December 31, 2013, the full time equivalent (FTE) employee count for Pacific Power declined significantly during the test year and continued to decline measurably through October 2014, just prior to the evidentiary hearing in this case (*i.e.*, December 16-19, 2014). Providing details, Public Counsel says that:

During the test year, PacifiCorp's employee count declined by 115.5 employees. Six months later, by June 2014, the employee count had declined by another 27 FTEs, such that the actual employee level was 66.5 FTE lower, or 1.24% below the average count for the test year upon which Pacific Power based its labor costs. Additional data provided to Public Counsel after the filing of Pacific Power rebuttal shows (*sic*) that FTE counts continued to decline every month after June 2014, until November, just one month before the hearing.⁴³

37 Pacific Power argues that “[t]he Company demonstrated that the reductions in staffing it is currently experiencing are temporary.”⁴⁴ The Company, however, offers no cite to the record pointing us to its demonstration of this asserted fact. Mr. Stuver's testimony, adopting that of Mr. Wilson in this case, is strikingly similar to Mr. Wilson's testimony in Docket UE-100749. In both cases, the Company's witnesses:

- Acknowledge that evidence presented by Public Counsel shows reduced levels of employees through the test period.
- Claim these reductions are temporary.
- Testify that Pacific Power requires a basic minimum level of staffing to ensure that its business operates smoothly.

⁴² *Id.* ¶ 54.

⁴³ *Id.* ¶ 56. We note that parties and the Commission, in prior orders, sometimes refer to Pacific Power as PacifiCorp.

⁴⁴ Pacific Power Initial Brief ¶ 131.

- Testify that the Company is actively recruiting to fill the vacant positions.

Mr. Stuver's testimony in this case nowhere rebuts that the Company has experienced a net reduction in FTE employees over a significant period of time.

38 Finally, Pacific Power argues that its updated business plan in the fall of 2014 shows 5,377 employees for the end of 2015. The Company states in addition that:

The test period average FTE complement of 5,375 closely approximates the *budgeted* FTE complement. In addition, the Company uses contract employees to backfill vacancies, and the expenses associated with retaining contract employees are roughly comparable to the expenses of the FTE employees.⁴⁵ Public Counsel's proposal would prevent the Company from recovering expenses that are likely to be incurred regardless of whether the Company permanently fills all the current FTE employee vacancies.⁴⁶

39 Turning to Pension Expense and OPEB, Public Counsel argues that Pacific Power's pension costs have declined significantly in 2014 since the amount recorded in the Company's books for the 2013 test year, by an amount of \$16.8 million.⁴⁷ Similarly, the Company's OPEB costs declined between the 2013 test year and 2014, from \$2.7 million to \$485,000, a reduction of over \$2.1 million.⁴⁸ Both the 2014 pension expense and the 2014 OPEB expense are based on the 2014 actuarial assumptions Pacific Power selected at the end of 2013, and upon the actual 2013 plan experience. Ms. Ramas testifies for Public Counsel that:

In the Pacific Power Response to Public Counsel Data Request No. 66, the Company provided the most recent pension actuarial report from the actuarial firm it uses, Towers Watson, dated January 2014. At page 4 of the actuarial report, Towers Watson describes the "significant reasons" for the reduction in the net periodic cost, as well as the

⁴⁵ *Id.* at 496:15-25, 497:1.

⁴⁶ Pacific Power Initial Brief ¶ 132 (emphasis added; internal citations to Mr. Stuver's testimony omitted).

⁴⁷ Public Counsel Initial Brief ¶ 60.

⁴⁸ *Id.* ¶ 65.

improvement in the funded position, as caused by four factors. These include: 1) the return on the fair value of plan assets was greater than expected improving the funded position; 2) the return on the market-related value of plan assets was greater than expected reducing the pension cost; 3) contributions to the plan during 2013 reduced the net periodic costs and improved the funded position; and 4) the discount rate (which is one of the actuarial assumptions) increased 75 basis points reducing the net periodic cost and improving the funded position.⁴⁹

Thus, Public Counsel says, these reductions are known and measurable changes that reflect the impacts of actuarial assumptions that were selected at the end of the test year.⁵⁰

40 Pacific Power argues that Public Counsel’s proposed adjustment to Pension and OPEB expenses violates the matching principle by focusing on one element of labor expense while ignoring other elements of labor expense, such as increased health care costs, that may offset the reduction. The Company’s rebuttal testimony, however, includes no showing that this is so. Nor is there other evidence in the record that demonstrates the Company’s point. Instead of presenting evidence, Pacific Power asks us to rely in this case on its argument that:

The Company’s wage and labor proposals in this case are consistent with its prior rate case filings, in which pension and OPEB expenses, as well as other labor-related expenses, are based on the historical test year. In the 2010 case, the Commission approved the Company’s *pro forma* wage adjustment while noting the Company “did not adjust changes in workforce levels, employee benefits and incentives, or pensions.”⁵¹

41 *Commission Determination:* Pacific Power’s approach to adjusting wages, contrary to the Company’s claim, is not “consistent with Commission precedent.” We reject it here.

⁴⁹ Ramas, Exh. No. DMR-1CTr at 26:8-19.

⁵⁰ Public Counsel Initial Brief ¶ 62 (citing *id.*)

⁵¹ *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 226 (Mar. 25, 2011).

42 Addressing the issue of employment levels in Docket UE-100749, the Commission said:

We do not lightly reject the Joint Parties argument that all wage increases in 2010 should be eliminated because workforce reductions can offset any increases. . . . However, there are two reasons why, in this case, we cannot make the requested adjustments.

First, although it appears that workforce levels are lower, there is insufficient evidence in this record to quantify a potential offset to the revenue requirement. No witness of the Joint Parties offered an adjustment for us to evaluate or for the other parties to critique. Accordingly, we would be creating an adjustment out of an imprecise record on this point, a task we are reluctant in this instance to undertake.

Second, even if the proposed adjustment could be precisely quantified, the Joint Parties do not demonstrate that these are permanent work force reductions. The Company persuasively countered that the reduction in workforce levels is temporary and the slight downward trend is due to a hiring lag.⁵²

Neither of these deficiencies is present in this case. Ms. Ramas quantifies the impact of the test period and post test period reductions in FTEs. The record demonstrates that the reductions in workforce reflect a continuing trend over several years. Indeed, the benefit of hindsight, coupled with evidence in this case, shows that Pacific Power's assertion in 2010 that declining FTEs represented nothing more than a temporary condition proved not to be accurate.

43 In 2010, the Company's employee count average during the test year ending December 31, 2009, was 5,651.⁵³ The actual count as of December 31, 2010, apparently was 5,586.⁵⁴ By the time of this case, these figures stood at 5,375 for the average test year FTE count, and 5,308 as of December 31, 2014. Thus, Pacific

⁵² *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶¶ 230-32 (Mar. 24, 2011).

⁵³ *Id.* ¶ 232, n. 334.

⁵⁴ *Id.*

Power today has nearly 300 fewer employees than it did in 2009 and 2010, roughly a 5 percent reduction in the Company's workforce over a period of six years. Evidence in this case shows definitively that this long-term trend continued during the 2013 test year and during the pendency of this case through at least June 2014.⁵⁵ Even so, Pacific Power argues we should adjust test year wages using forecasted wage increases that extend out to March 2016, 27 months beyond the end of the test year, without making any adjustment for employee counts.

44 The Company's argument that its budgeted FTEs as of fall 2014 closely approximate its test-year average FTEs does not justify using the test year average as Pacific Power proposes. As Pacific Power is fully aware, Washington uses a hybrid test year approach that allows *pro forma* adjustments only for known and measurable changes—not budgeted or projected changes—that occur, generally within a reasonable time after the end of the test year and, with some exceptions,⁵⁶ almost never more than 12 months after the end of the test year.⁵⁷

45 On the subjects of Pension Expense and OPEB, we begin with the observation that each case must be decided exclusively on its own record.⁵⁸ It is not at all clear from the order in Docket UE-100749 that the Commission's determination of these issues in the Company's favor was firmly grounded in the record of that proceeding. Indeed, we cannot discern today exactly upon what basis the Commission decided the matter as it did. This, however, is of no consequence to us in this proceeding. What

⁵⁵ See Revised Exh. No. DKS-3CX (Public Counsel cross-examination exhibit for Company witness Mr. Stuver).

⁵⁶ See *supra* ¶ 18. The only regular exception the Commission makes is for power costs, which are a very significant part of electric utility expense and which are updated with a very high level of analytical rigor and readily available market data concerning fuel costs, and other costs.

⁵⁷ We note that it is even exceptional for the Commission to allow *pro forma* adjustments beyond a few months after the end of the test year. The Commission has relaxed this careful approach somewhat during recent years, risking violation of the matching principle, in an effort to address concerns that regulatory lag has been increasingly problematic during a period of unusually high capital investment. The Commission also has used other approaches, such as use of EOP rate base instead of the preferred AMA approach, and allowance of attrition adjustments, to address this problem. Nevertheless, companies we regulate continue to file regularly for general rate increases. Pacific Power, for example, has filed one general rate case after another, year after year, as exemplified by its filing of this case only five months after the Commission authorized rate increases in Docket UE-130043 in 2013.

⁵⁸ RCW 34.05.

matters is that Pacific Power offers nothing in the way of evidentiary support for its position in this case. Moreover, the Company's arguments are unpersuasive considering that the Company proposes *pro forma* adjustments far beyond the end of the test year for the components of its labor costs that result in a higher revenue requirement, but argues against recognizing any known and measurable offsets for the corresponding post-test year period.

46 We accordingly accept Public Counsel's recommendation, based on Ms. Ramas' analysis, to reduce Pacific Power's pension expense by \$16.8 million on a Company basis. According to Ms. Ramas, after removing the portion allocated to capital and non-utility, the impact is a reduction of \$11.7 million on a Company basis, and \$761,547 on a Washington-jurisdictional basis.⁵⁹ In addition, we accept Public Counsel's recommendation that OPEB expense should be reduced by \$2.21 million. After removal of amounts allocated to capital and non-utility, the reduction is \$1.5 million on a total Company basis, and \$100,686 for Washington.⁶⁰

2. Insurance Expense (Adjustment 4.7)

47 Pacific Power's adjusted test year liability insurance expense is based on a six-year average of the liability expense accruals the Company booked from 2008 through the end of the test year. The Company voluntarily removed several accruals booked in 2012 and 2013, as shown in in the table below, resulting in a six-year average of \$9,402,352 on a Company basis, with \$644,437 allocated to Washington. The six-year rolling average approach is intended to normalize fluctuations in insurance expenses that occur year-over-year.⁶¹ The Commission approved this method as part of a settlement in Pacific Power's 2011 GRC and in the Company's 2013 GRC where it was not contested.⁶²

48 Staff accepts the use of a six-year rolling average, but proposes to replace the Company's 2012 insurance year net expense level of \$30,859,248 with the 2007 insurance year expense level of \$10,087,289, for purposes of calculating the six year

⁵⁹ Ramas, Exh. No. DMR-1CTr at 27 (referencing Schedule 9).

⁶⁰ *Id.* at 28:14-20 (referencing Schedule 10).

⁶¹ Siores, Exh. No. NCS-10T, at 8:18-20.

⁶² *WUTC v. PacifiCorp*, Docket UE-111190, Settlement Stipulation at 5 (Feb. 21, 2012). *See WUTC v. PacifiCorp*, Docket UE-130043, Revised Final Issues List (Aug. 23, 2013)

average.⁶³ Mr. Ball testifies that the Company's actual 2012 insurance level is not representative of a normal level of expense that can be expected to occur during the rate year. Indeed, he observes, it is approximately 10 times higher than the 2011 expense level and three times higher than the next highest expense level, the amount reflected for 2007.⁶⁴ Staff's adjustment reduces the Company's proposed adjustment by \$248,323 on a Washington basis.

49 Public Counsel recommends removing \$20 million in reserves from the Company's 2012 liability and property damage expenses.⁶⁵ Ms. Ramas testifies that Pacific Power, in response to discovery, explained that the net expense shown for 2012 is significantly higher than the amounts for the remaining years because the Company booked "increased reserves required for certain fires, an oil spill, personal injury claims, and other injuries and damages claims that occurred in 2012."⁶⁶ Based on her examination of data from 2006 forward, Ms. Ramas agrees with Staff's assessment and gives her opinion that "the expense accrual recorded in 2012 is an anomaly."⁶⁷

50 In rebuttal, the Company argues Public Counsel and Staff are subjectively and arbitrarily removing one year simply because it is "too high".⁶⁸ Responding to Public Counsel's statement that the 2012 insurance expenses accrued on a Company-wide basis are in part allocated to Washington because of the System Overhead allocation factor in the West Control Area (WCA) inter-jurisdictional cost allocation methodology, the Company reasserts the appropriateness of allocating insurance expense using this allocation factor.⁶⁹ The Company, however, does not provide a justification for the increased reserve requirements for the specific items identified in Ms. Ramas' confidential testimony for Public Counsel or counter Staff's characterization of the 2012 level as non-representative for use in the six year average for test-year purposes.

⁶³ Ball, Exh. No. JLB-1T, at 14:1-3, 15-17.

⁶⁴ *Id.* at 14:7-14.

⁶⁵ Ramas, Exh. No. DMR-1CT, at 34:1-2.

⁶⁶ *Id.* at 32:7-15 (quoting from Pacific Power Response to Public Counsel Data Request No. 78).

⁶⁷ *Id.* at 32:19-22.

⁶⁸ Siores, Exh. No. NCS-10T, at 8:6-17.

⁶⁹ Siores, Exh. No. NCS-1T, at 9:1-3. For a brief history of the WCA methodology, *see infra* ¶ 69, n. 94.

- 51 Asked by Public Counsel during discovery to explain why Pacific Power excluded \$16 million in potential liability from its 2012 insurance costs, the Company responded that “these reserve amounts were excluded from the calculation of the average cost because PacifiCorp intends to seek insurance recovery when these liability claims are fully settled.”⁷⁰ Mr. Stuver initially affirmed this rationale and testified that the incident in question, the “Wood Hollow fire,” remained subject at the time of hearing to “ongoing mediation and settlements with the Wood Hollow claimants.”⁷¹ Mr. Stuver also acknowledged during cross-examination that liability has not yet been established for the claims accrued on the Company books and contested by Public Counsel.⁷² These matters, too, were unresolved in terms of what final liability the Company might incur and both were subject to ongoing settlement negotiations and mediation.⁷³ In these ways, as developed through Mr. Stuver’s cross-examination, these claims are indistinguishable from the Wood Hollow fire claims that the Company excluded from insurance expense for 2012 because the incident is the subject of “ongoing litigation which makes the total costs attributable to this fire not known and measurable at this time.”⁷⁴ Rather than providing a satisfactory rationale as to why the additional claims, also still in dispute, were not likewise removed from the liability expense adjustment because they are not known and measurable, Mr. Stuver retreated from the rationale he previously affirmed with respect to the Wood Hollow fire and expressed his opinion that all of these claims were known and measurable and should be included in calculating the six year average.⁷⁵
- 52 *Commission Determination:* The purpose of the six-year average as a replacement for the test-year booked insurance costs is to provide a normalized level of expense, which the parties agree is a proper way to determine this expense for inclusion in

⁷⁰ Exh. NCS-21-CX. The Commission approved the WCA approach in 2007. *See WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08, ¶¶ 56-57 (June 21, 2007).

⁷¹ Stuver, TR. 483:7-8.

⁷² Stuver, TR. 483:1-6. *See also* Exh. No. NCS-22 C CX, a confidential exhibit that provides details concerning three incidents during 2012, including the two Public Counsel contests, that show them to be unresolved and subject to settlement negotiations.

⁷³ *Id.*

⁷⁴ Exh. No. NCS-26CX; Stuver, TR. 481:3-20.

⁷⁵ Stuver, TR. 483:18-25.

rates. The use of averages of brief periods of years, however, is not entirely straightforward when the data reflect extraordinarily high costs such as the insurance reserves set aside in 2012. The extreme variance in costs exhibited by the Company's 2012 expense relative to the other years in the record is sufficient in itself to justify the sort of adjustment Staff proposes.

53 In this case, however, Public Counsel developed evidence that provides an even a more compelling reason to make adjustments. As developed by Public Counsel, the record shows that Pacific Power itself removed from the six-year average significant reserves booked for incidents that remain subject to litigation and in the process of settlement negotiations because the costs cannot be considered known and measurable. Yet, the Company included reserves for other incidents that also remain unresolved without satisfactorily explaining why we should consider the costs of these matters to be known and measurable. Not only are these costs not presently known and measurable, it may turn out in the final analysis that the Company was negligent or even grossly negligent with respect to the underlying incidents. This could give the Commission reason not to allow the costs in rates for recovery even if the level of costs is firmly established.

54 Considering this uncertainty, we find it appropriate to accept Public Counsel's recommendation to exclude \$20 million in reserves from insurance expense for the two relevant events. We accept Public Counsel's proposed adjustment for a \$20 million reduction in 2012 insurance expense. According to Ms. Ramas, this reduces the average expense calculated by the Company by \$3,333,333. We determine accordingly that Pacific Power's test year insurance expense should be reduced by \$3,333,333 on a total Company basis and by \$228,467 on a Washington-allocated basis.

3. IHS Global Insight's Escalation Factors (Adjustment 4.13 - Operations & Maintenance (O&M) Expenses other than labor and power related O&M)

55 Pacific Power, borrowing from practices accepted in two of its three jurisdictions that use a future test year approach to ratemaking,⁷⁶ proposes to escalate its non-labor

⁷⁶ Utah and Oregon have approved the use of these escalation factors for forecasting future test period costs. Wyoming, also a state that uses a future test year, has rejected their use. See Boise White Paper Initial Brief ¶ 62 (citing *Re Application of Rocky Mountain Power for Approval of a*

Operations & Maintenance and Administrative & General expenses using proprietary indices prepared by IHS Global Insight.⁷⁷ These are not indices prepared with specific reference to Pacific Power. They rely on data from the U.S. utility industry generally. IHS Global Insight assesses electric utility costs for materials and services (excluding labor) and develops escalation factors broken out by FERC Uniform System of Accounts functional subcategory.⁷⁸ The individual indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses.⁷⁹ The Company proposes applying the IHS Global Insights indices, by FERC function, to the Company's historical test year expense levels as a means to forecast these costs for Pacific Power during the rate year, through March 31, 2016.⁸⁰

56 Staff, Boise White Paper, and Public Counsel all oppose the Company's proposal. They argue that it is too far a departure from historical test year principles, including most significantly that *pro forma* adjustments to test period costs must be known and measureable.

57 Staff argues that because there is no direct connection between the IHS Global Insight indices and Pacific Power's operations in Washington, the Company's proposed adjustment simply fails to reflect any specific known and measurable cost the Company incurs in serving Washington ratepayers.⁸¹ "PacifiCorp's proposal fails to meet any reasonable interpretation of the known and measurable standard."⁸²

General rate Increase, Wyoming PSC Docket No. 20000-446-ER-14, Order ¶¶ 45, 174 (Dec. 30, 2014)).

⁷⁷ Pacific Power Initial Brief ¶134 (citing Dalley, Exh. No. RBD-1T 9:8-13, 10:20-22; Dalley, Exh. No. RBD-3T 7:11-23, 11:19-21). IHS Global Insight is a national economic forecasting consulting company that is widely used to develop economic forecasts. For the utility industry, IHS Global Insight provides industry-specific escalation indices, developed at the Federal Energy Regulatory Commission account functional level. A description of the model used by IHS Global Insight to develop its O&M and A&G indices is attached to Mr. Dalley's rebuttal testimony as Confidential Exh. No. RBD-5C.

⁷⁸ *Id.* (citing Siores, Exh. No. NCS-1T 19:5-9).

⁷⁹ *Id.* (citing *Id.* at 19:9-11).

⁸⁰ *Id.* (citing Dalley, Exh. No. RBD-1T 10:22-23).

⁸¹ Staff Initial Brief ¶ 140.

⁸² *Id.*

58 Public Counsel argues that

Rates in Washington are based on actual historical test year costs and pro-forma known and measurable adjustments, not on estimates and projections. Absent the adoption of a future test year in Washington, with necessary protections and parameters, use of escalation factors in this manner is not reasonable.⁸³

It notes that Pacific Power has neither performed any analysis or study, nor commissioned any third party analysis or study, to demonstrate that the O&M and A&G expenses for Pacific Power have historically been increasing at similar rates to the IHS Global Insight factors.⁸⁴ The Company submitted no such supportive analysis for the record in this case.

59 Faced with this strong opposition, the Company's principal argument in rebuttal is that its claims of historical under-recovery of costs in Washington should persuade the Commission to largely ignore longstanding regulatory principles and allow "discrete" adjustments that would increase the Company's revenue requirement (*i.e.*, expense recovery) without giving any consideration to possible offsetting revenue during the post-test year period.⁸⁵ The Company rationalizes this in its Initial Brief with the argument that "[t]he Company's load forecast shows only 0.2 percent load growth expected between the test year and the rate year, so any changes in the Company's revenues will be substantially less than the changes in costs."⁸⁶

60 *Commission Determination:* The Company's proposed adjustments using the IHS Global Insight indices do not present known and measurable *pro forma* adjustments. The Company supports the use of the IHS Global Insight indices as addressing under-earnings that it claims result from Washington's use of a historic test year. Essentially, this is another effort by Pacific Power to force the square peg of a future test year approach to ratemaking into the round hole of our hybrid test year approach.

⁸³ Public Counsel Initial Brief ¶69 (citing *PSE 2009 GRC*, Order 11, ¶ 26).

⁸⁴ Public Counsel Initial Brief ¶ 68 (citing Dalley, TR. 383:21-385:14).

⁸⁵ Dalley, Exh. No. RBD-3T, at 12:9-17.

⁸⁶ Pacific Power Initial Brief ¶ 137 (citing Duvall, Exh. No. GND-1CT 16 Table 3).

- 61 As Staff points out, under this state's approach to ratemaking the Company should perform an attrition study to show that Company specific trends in non-labor and non-power O&M and A&G expense exceed revenue growth and efficiency gains.⁸⁷ Pacific Power, however, has performed no such study either in this proceeding or in any of its previous general rate cases. Indeed, there is no evidence in this record that Pacific Power has under recovered these expenses in Washington.
- 62 Further, the Company does not demonstrate that its historical growth rate in these expense categories corresponds in any way to the HIS Global Insight indices escalation rate. Finally, the IHS Global Insight indices are based on historical inflation rates, not on forward looking estimates of inflation, which would need to be considered.
- 63 We therefore reject Pacific Power's proposal to use the IHS Global Insight indices to adjust these operating expenses. Even were we to adopt a future test year approach in Washington, we are not convinced the use of the IHS Global Insight indices would be appropriate because they are neither specific to Pacific Power, nor have they been tested against the Company's actual experience.⁸⁸

C. Net Power Costs – *Pro Forma* (Adjustment 5.1.1)

- 64 Pacific Power requests *pro forma* Net Power Costs (NPC) in the WCA of approximately \$592.7 million, or \$135.6 million on a Washington-allocated basis, for the 12 months ending March 31, 2016.⁸⁹ This includes approximately \$10 million in costs the Company incurs from out-of-state Qualifying Facility (QF)⁹⁰ Purchase

⁸⁷ See Ball, Exh. No. JLB-1T at 16:11-7:3.

⁸⁸ We note that Wyoming, a future test period state, has rejecting the use of these indices by Rocky Mountain Power, PacifiCorp's operating division serving that state. *Re Application of Rocky Mountain Power for Approval of a General rate Increase*, Wyoming PSC Docket No. 20000-446-ER-14, Order ¶¶ 172-173 (Dec. 30, 2014).

⁸⁹ Pacific Power Initial Brief ¶¶ 61-86.

⁹⁰ QFs were created by Congress in the Public Utilities Regulatory Policy Act (PURPA). [Pub.L. 95-617](#), 92 [Stat. 3117](#) (enacted November 9, 1978). PURPA was part of the [National Energy Act](#) of 1978. PURPA established this new class of generating facilities that receive special rate and regulatory treatment and requires regulated electric utilities such as PacifiCorp to buy power from them, if their cost is less than the utility's own "avoided cost" rate determined by each state public utility commission.

Power Agreements (PPAs). Under the Commission's 2007 order approving the WCA inter-jurisdictional cost allocation methodology, Pacific Power must allocate QF costs based on "situs," allocating the costs of these facilities to the states in which they are located.⁹¹ Staff, Public Counsel, and Boise White Paper ask the Commission to follow the WCA in this case and disallow these out-of-state QF costs, reducing accordingly Washington NPC.⁹²

65 Boise White Paper recommends additional NPC adjustments by imputing benefits related to the Company's participation in the Energy Imbalance Market (EIM) with the California Independent System Operator Corporation.⁹³ In addition, Boise White Paper asks the Commission:

- To accept its proposed reduction to NPC related to Network Integration and Transmission (NT) Service from the Bonneville Power Administration (BPA) rather than the smaller amount recommended by Pacific Power.⁹⁴
- To remove duplicative charges Boise White Paper contends result from the Company double-counting of inter-hour wind and load integration costs through two separate NPC charge items.⁹⁵
- To exclude the 2013 Chehalis outage from GRID model outage rate calculations because the outage: 1) is not representative of normal plant operations in the rate period; and 2) resulted from imprudent operation.⁹⁶

1. Qualifying Facilities Contract Costs

66 The Commission addressed at length in its Final Order in Pacific Power's 2012/2013 GRC the Company's proposals in that case to change the way PacifiCorp's inter-

⁹¹ *WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08, ¶¶ 56-57 (June 21, 2007).

⁹² Staff Initial Brief ¶¶ 25-70; Public Counsel Initial Brief ¶¶ 39-40; Boise White Paper Initial Brief ¶¶ 65-75.

⁹³ Boise White Paper Initial Brief ¶¶ 76-83.

⁹⁴ *Id.* ¶ 84.

⁹⁵ *Id.* ¶¶ 85-87.

⁹⁶ *Id.* ¶¶ 88-90.

jurisdictional costs are allocated to Washington using the WCA inter-jurisdictional cost-allocation methodology.⁹⁷ The most significant change the Company proposed would have added more than \$10 million to Washington rates by changing the West Control Area method of allocating QF power costs the Company incurs in Washington, Oregon, and California.⁹⁸ The Commission rejected Pacific Power's proposal and discussed at length the evidence, the parties' arguments, and the bases for its determination.⁹⁹ The Commission also discussed what would be required to support any future proposal to change the WCA methodology.¹⁰⁰

- 67 In this case, Pacific Power again requests authority to abandon the WCA situs allocation methodology for PURPA QF power costs. Although it presents three alternative means to change the methodology for allocating these costs, the primary proposal is identical to what it proposed in Docket UE-130043 and the fundamental argument remains the same: that is, the WCA allocation methodology that does not allow Pacific Power to allocate the costs of Oregon and California QFs to Washington should be abandoned in favor of a methodology that effectively allows the allocation of such costs to Washington.
- 68 *Commission Determination:* In Pacific Power's 2012/2013 GRC the parties presented extensive testimony and argument concerning the QF cost allocation issue. The Commission discussed the issue at length in Order 05, its Final Order in the case entered on December 4, 2013.¹⁰¹

⁹⁷ *WUTC v. PacifiCorp*, Docket UE-130043, Order 05 ¶¶ 74-94 (December 4, 2014).

⁹⁸ PacifiCorp's costs are allocated among five of the six states in which it does business as either Pacific Power (Oregon, Washington, and California) or Rocky Mountain Power (Idaho, Utah and Wyoming) using the so-called Revised Protocol. The Commission rejected the use of this allocation methodology in 2006. *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 ¶ 64 (April 17, 2006). In the Company's next general rate case the Commission approved PacifiCorp's proposed WCA cost-allocation methodology for Washington. *WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08, ¶¶ 49-52 (June 21, 2007). Pacific Power used the approved WCA method in its 2008, 2009, 2010 and 2011 general rate cases in Dockets UE-080220, UE-090205, UE-100749, and UE-111190, respectively. The Commission extended the WCA trial period in the 2011 proceeding, as the parties requested and, following an unsuccessful collaborative process among interested stakeholders, Pacific Power again used the WCA, albeit unilaterally proposing to make several changes, including changing the allocation method for QF costs using the Revised Protocol approach.

⁹⁹ Docket UE-130043, Order 05 ¶¶ 95-114.

¹⁰⁰ *Id.* ¶¶ 92-94.

¹⁰¹ *Id.* ¶¶ 74-94.

- 69 Pacific Power, bypassing its opportunity to seek reconsideration under RCW 34.05.470, appealed the Commission's order to the Washington Court of Appeals, Division II, on January 2, 2014. The Company makes essentially the same arguments to the Court concerning the allocation of QF costs that the Commission expressly rejected in Order 05. The Commission answers these arguments in its brief to the Court, filed on December 24, 2014. As of the date of this Order, that case is still pending in the Court of Appeals.
- 70 Pacific Power filed this rate case on May 1, 2014, making the same QF cost allocation proposal. Again in this case, the parties present extensive testimony and argument, much of which repeats in one form or another what the Commission heard in the prior case and summarizes what the Commission said in Order 05, entered just five months before Pacific Power filed this case. We decline to discuss, nor will we discuss this matter at length again so recently on the heels of Order 05, especially given that the matter is still pending judicial review.
- 71 Pacific Power seeks to re-litigate the Commission's decision in UE-130043 to depart from the WCA inter-jurisdictional cost allocation methodology and, by one means or another, include the costs of Oregon and California QFs in Washington rates. At the same time, Pacific Power is pursuing the identical issue, making the same arguments, in the Court of Appeals. The Commission is not obligated to decide this issue again in this proceeding and exercises its statutory authority to decline to do so.
- 72 RCW 80.04.200 states, in pertinent part:
- Any public service company affected by any order of the commission, and deeming itself aggrieved, may, after the expiration of two years from the date of such order taking effect, petition the commission for a rehearing upon the matters involved in such order, setting forth in such petition the grounds and reasons for such rehearing, which grounds and reasons may comprise and consist of changed conditions . . . , or that the effect of such order has been such as was not contemplated by the commission or the petitioner, or for any good and sufficient cause which for any reason was not considered and determined in such former hearing.

This statute establishes a two-year period during which an issue decided by the Commission need not be reheard. The meaning of this statute was tested in 1997.¹⁰² The Washington Supreme Court held:

The same issues which were considered in the depreciation case are the issues the Company sought to introduce in the rate case. Therefore, under RCW 80.04.200, the Commission did not have to rehear those issues in the rate case only months after they had been considered in the depreciation case. Under this statute, whether or not US West had “new” evidence or wished to argue that conditions had changed with regard to competition, the Commission was not obligated to hear the issues again within the two-year period.¹⁰³

73 Pacific Power’s QF proposal in this case falls squarely within the language of RCW 80.04.200, as discussed by the Supreme Court in *US West*. The Commission decided the QF issues in the Company’s 2013 rate case, which was decided only five months before the Company filed this case seeking in one fashion or another the same result previously rejected. This is well within the two-year window set forth in the statute and the Commission is under no obligation to rehear the matter. Further, Pacific Power put this matter before the Court of Appeals and we should not, for reasons of

¹⁰² *US West Communications, Inc. v WUTC*, 134 Wn.2d 74 (1997). The Supreme Court’s Opinion relates that:

In May 1994, US West filed its petition in the depreciation case seeking adjustments of its depreciation rates and accounting methodology. . . . In February 1995, US West filed this rate case. In May 1995, the Commission filed its decision in the depreciation case. . . . In January 1996, after motion, responses and argument, the Commission issued its Eleventh Supplemental Order in the rate case excluding the depreciation evidence from being heard again in the rate case. . . . US West appealed the rate case to the Superior Court, arguing that the Commission artificially separated the evidence in the depreciation case from the evidence in the rate case. The Superior Court held that it was not incumbent on the Commission to revisit the same issues in the rate case that had just been considered in the depreciation case.

134 Wn. 2d at 103-04. US West argued to the Supreme Court that the Commission “was required to consider the depreciation evidence again in the rate case” and “it had new and updated evidence to present on the depreciation issues not available in the depreciation case.” *Id.* at 104.

¹⁰³ *Id.* at 105. The Court acknowledged that it is within the Commission’s discretion under RCW 80.04.200 to rehear issues within the two year stay-out period, and that “[d]iscretionary decisions of the Commission are only set aside on a clear showing of abuse.” *Id.*

comity, take up again the same issues that are pending there. The effect of our determination to not rehear this question is to reject for purposes of this case Pacific Power's untimely proposal that we abandon the WCA inter-jurisdictional cost allocation methodology for QF facilities.

2. Jim Bridger Coal Costs

- 74 Mr. Duvall testifies that *pro forma* coal fuel expense increased by \$2.3 million on a Washington-allocated basis, from \$48.3 million in the Company's 2013 GRC to \$50.6 million in this case.¹⁰⁴ This net increase reflects an approximate \$0.4 million decrease in volumes and a \$2.7 million increase in costs due to higher prices for coal from the Bridger Coal Company (BCC) and the Black Butte mine, which furnish fuel to Jim Bridger, and the Rosebud mine, which furnishes fuel to Colstrip. The current Black Butte coal supply agreement was through 2014, with an extension into 2015 to allow for delivery of previously deferred contract tonnage. The previously deferred contract tonnage was projected to be delivered in the first quarter of 2015 and the Company assumed unchanged pricing terms for the first quarter of 2015.¹⁰⁵ Pacific Power projected increases for the balance of 2015 for Black Butte and BCC for the full 12 months after the end of the test period. The Company includes *pro forma* period costs for coal at the Colstrip facility based on Western Energy's 2014 Annual Operating Plan (AOP) for the Rosebud mine, which was published in fall 2013.¹⁰⁶
- 75 The Company's rebuttal testimony includes an update that increases NPC by just under 11 percent relative to the as-filed NPC: \$5.4 million on a Washington-allocated basis. This increase is largely attributable to changes in coal prices and increased volumes at the Jim Bridger coal plant in Wyoming.¹⁰⁷
- 76 Ms. Crane testifies the price of Black Butte coal reflected in her rebuttal NPC is the result of a higher delivered price obtained in response to a request for proposals for Wyoming coal by the Bridger plant owners in June 2014.¹⁰⁸ The increase in BCC

¹⁰⁴ Duvall, Exh. No. GND-1CT at 18:2-7.

¹⁰⁵ *Id.* at 19:17-20:4.

¹⁰⁶ *Id.* at 18:14-17.

¹⁰⁷ Crane, Exh. No. CAC-1CT 2:13-15; 3:6-12.

¹⁰⁸ *Id.* at 4:12-19.

prices reflects the Company's updated mine plan, which was prepared in July 2014 and finalized in November 2014.¹⁰⁹

- 77 The Company's rebuttal NPC costs also include updated coal prices for the Colstrip plant as a result of an updated operating plan for the Rosebud mine.¹¹⁰ Ms. Crane testifies that the Company's direct case reflected mining costs based on the mine operator's 2014 AOP. In October 2014, the mine operator provided the Colstrip owners with the final 2015 AOP increasing WCA NPC by a small amount.¹¹¹
- 78 Although the parties elected not to contest these adjustments at the close of the case, Boise White Paper expressed by means of a motion to strike testimony its dissatisfaction with having significant price increases brought to the parties' and the Commission's attention only in the Company's rebuttal testimony. The Commission denied the motion because it does not appear the Company intentionally set out to prejudice the other parties with respect to the coal price update. Indeed, the Company stated that it had no objection to the parties having an opportunity to file supplemental testimony on the issue. In Order 07, denying Boise White Paper's motion, the Commission invited parties to seek leave to file supplemental testimony if they wished, and stated it "would be receptive to accommodating any such request" and, if asked, would "establish appropriate additional process on a reasonable schedule."
- 79 We mention these facts because the Commission is concerned when a company presents significant changes to its case at the time of its rebuttal filing. This can be unsettling to the parties and potentially can disrupt a carefully planned procedural schedule close in time to a planned evidentiary hearing. Thus, we do not wish to leave unremarked the event of Pacific Power's late notice of significant price increases in coal fuel costs in this case. We caution that the Commission may not be receptive in a future case to allowing such testimony, if challenged, and may be particularly disinclined to do so on any issue other than one affecting net power costs. The Commission generally is more lenient with respect to power cost updates because these most often result from changes in the fuel markets that are readily verifiable from various public sources. Pacific Power's coal cost update is a bit of a closer call,

¹⁰⁹ *Id.* at 5:18-20; *see also* Declaration of Cindy A. Crane in Support of Pacific Power's Response in Opposition to Motion to Strike [Ms. Crane's rebuttal] Testimony at ¶¶ 5-6.

¹¹⁰ *Id.* at 11:6-13.

¹¹¹ The exact amount is confidential as shown in Crane, Exh. No. CAC-1CT at 11:11-13.

based as it is on the results of a request for proposals (RFP) issued in June 2014, the results of a process that we had no opportunity to evaluate for prudence.

80 In any event, we take this opportunity to caution that in our proceedings the purpose of the rebuttal round of testimony is to provide a party seeking a rate increase an opportunity to rebut evidence presented by other parties in their response testimonies. Any evidence presented on rebuttal that is outside this purpose may be rejected. In the final analysis, however, we accept these adjustments to NPC as a result of the changes in coal prices at Jim Bridger, and the minor modification at the Colstrip facility, as being appropriate and meeting the known and measurable test. These adjustments to the NPC for higher contractual coal costs will result in a \$25 million increase on a total WCA basis and \$5.7 million on a Washington-allocated basis.

3. Energy Imbalance Market Costs

81 PacifiCorp and the California Independent System Operator (CAISO), as sole participants, launched the Western Energy Imbalance Market (EIM) on November 1, 2014. The EIM is a voluntary, sub-hourly market administered by CAISO serving the PacifiCorp West, PacifiCorp East, and CAISO Balance Authority Areas (BAA). It is expected to provide efficient dispatch of imbalance energy across the BAAs every five minutes.¹¹²

82 The Company does not reflect the imbalance market's impact on its rate base, rate year revenue, or expenses. Mr. Duvall testifies that the costs and benefits of the EIM are not sufficiently known and measurable at this time. He observes that the EIM is new and states that "key EIM components are still being developed and implemented."¹¹³ In addition, he points out that the expected imbalance costs and benefits may vary depending on transfer capability available, making costs and benefits difficult to forecast.¹¹⁴

83 Mr. Mullins, for Boise White Paper, testifies that "if the Commission determines other major pro-forma capital additions should be included in revenue requirement—such as the Merwin Fish Collector—then EIM costs and associated benefits should

¹¹² Mullins, Exh. No. BGM-5CT, at 2.1.1.

¹¹³ Duvall, Exh. No. GND-1CT, at 7:4-9.

¹¹⁴ *Id.* at 7:12-15.

also be reflected in revenue requirement.”¹¹⁵ Mr. Mullins testifies that the Company proposes to include in rates a number of post-test period capital projects with smaller capital budgets and later in-service dates than the EIM expenditures. Yet, he says, Pacific Power has not proposed that any costs or benefits of the EIM be reflected in rates. In Mr. Mullins’ view, the Commission should not apply “a double standard for determining which pro-forma capital and operating costs to include in revenue requirement.”¹¹⁶

84 To support his proposal Mr. Mullins relies on a March 2013 study prepared by Energy and Environmental Economics, Inc. (E3), titled “*PacifiCorp-ISO Energy Imbalance Market Benefits*” which examines both the feasibility and benefits of developing an EIM between PacifiCorp and the CAISO.¹¹⁷ Mr. Mullins argues that if the Company relied on the E3 report in its decision to participate in the EIM, then the same report should be sufficient enough to establish EIM benefits for ratemaking purposes.¹¹⁸ Relying solely on the report, Mr. Mullins provides discussion on the costs and benefits of the Company’s participation in the new EIM program. He begins by recognizing an estimated initial investment and operating costs of the Company by increasing expenses by \$237,000 in O&M expenses and increasing the test year’s rate base of \$1.2 million. The adjustments result in a \$394,087 increase in Pacific Power’s Washington allocated revenue requirement.¹¹⁹

85 The Company responds to Boise White Paper’s proposal by pointing out that it is currently impossible to project accurately the amount of offsetting benefits in the rate period.¹²⁰ Mr. Duvall testifies that because of Washington’s known and measurable standard, and its adherence to the matching principle, the Company decided not to include EIM costs and benefits in this filing.¹²¹ Mr. Duvall testifies that EIM benefits are “unlike other forecast items in this case because there is no actual or analogous

¹¹⁵ Mullins, Exh. No. BGM-1CT at 19:2-6.

¹¹⁶ *Id.* at 19:16-23.

¹¹⁷ Mullins, Exh. No. BGM-5CT.

¹¹⁸ Mullins, Exh. No. BGM-1CT at 31:5-9.

¹¹⁹ *Id.* at 21:3-7.

¹²⁰ Duvall, Exh. No. GND-4CT at 30:21-23.

¹²¹ *Id.* at 30:23-31:3.

historical data on which to base an economic forecast for ratemaking purposes.”¹²² In addition, the EIM is new and untested. He expects that a reasonable ramp-up period will be required before EIM benefits are fully realized and measurable.¹²³

86 Mr. Duvall’s “overarching criticism” of Boise White Paper’s reliance on the results of the E3 Report is that there is no nexus between the study and “the specific *pro forma* period in this case or the WCA methodology.”¹²⁴ In addition, according to Mr. Duvall, Boise White Paper’s proposed adjustments include benefits that are already reflected to some extent in the Company’s existing forecast and reflect a reduction in imbalance costs that are not included in the Company’s power cost model forecast or customers’ rates to begin with.¹²⁵

87 Mr. Duvall discusses, too, that “the Company used the E3 Report to verify that the EIM would be cost effective, not as a study to quantify its near-term benefits for ratemaking.”¹²⁶ He explains that the report is based on a forecast of the Western Electricity Coordinating Council’s 14-state region for 2017, with corresponding loads and market prices, with the benefits adjusted to 2012 dollars. Thus, the benefits determined by the E3 Report depend on the costs of system operation in 2017 and do not reflect costs included in the Company’s forecasted NPC in this case. Mr. Duvall states that “[d]ifferences include essential assumptions no party would accept for use in GRID in this rate case including different test period, forward price curves, transmission topology, and differences in the underlying production dispatch model and associated model architecture.”¹²⁷

88 Mr. Duvall, having stated the Company’s general objections to Boise White Paper’s proposal, also testifies in considerable detail concerning Pacific Power’s specific objections to imputing benefits for EIM Inter-Regional Dispatch, EIM Intra-Regional Dispatch, EIM Reserve Diversity, and Within-Hour Dispatch. Such evidence may prove useful in a future case, but we find no need to discuss it here where the issue

¹²² *Id.* at 31:18-23.

¹²³ *Id.*

¹²⁴ *Id.* at 33:18-34:6.

¹²⁵ *Id.* The Company’s proprietary power cost model is identified as GRID, the acronym for Generation Regulation Initiative Decision.

¹²⁶ *Id.* at 34:9-10.

¹²⁷ *Id.* at 34:14-18.

can be determined at the threshold and requires no nuanced analyses of specific issues beyond the threshold.

89 *Commission Determination:* While we find Boise White Paper’s arguments insightful, we find that Mr. Mullins’ estimates of costs and benefits are too uncertain to support the sort of adjustments he proposes on behalf of his client. As the EIM is still in its infancy from an operational standpoint, it makes more sense to consider the costs and benefits of this new intra-hour balancing tool in a future general rate case when the Company has more actual data and operational experience that corresponds to a test year. Contrary to what Mr. Mullins testifies, the E3 report, a planning document forecasting WECC-wide benefits in 2017, is not a proper basis upon which to determine costs that the Commission can consider to be known and measurable for purposes of setting rates in this case. Given that the E3 report is the principal basis upon which Mr. Mullins relies in estimating costs and benefits, we are constrained to reject Boise White Papers recommended adjustments to NPC in this case.

4. Network Integration and Transmission Service Costs

90 The Bonneville Power Administration (BPA) provides Network Integration Transmission Service (NT Service) to Pacific Power, which allows the Company to provide service to several areas in Washington and Oregon that Mr. Mullins refers to as “load pockets.” The Company included for recovery in rates the wheeling costs of the NT Service in power costs, calculating these costs using the non-coincident peak for each load pocket.

91 Mr. Mullins testifies for Boise White Paper that the billing factor assumed by the Company for NT Service is different than the actual billing factor in BPA’s Open Access Transmission Tariff (OATT),¹²⁸ which uses “the customer’s Network Load on the hour of the Monthly Transmission System Peak Load, as those terms are defined in BPA’s OATT.”¹²⁹ Mr. Mullins disputes the Company’s assumption that the non-coincident peak load equals the coincident peak load and testifies that “the Company’s calculation overstates the billing factor and related costs associated with BPA NT Service reflected in NPC.”

¹²⁸ Mullins, Exh. No. BGM-1CT at 45:1-9.

¹²⁹ *Id.*

- 92 In rebuttal, Mr. Duvall “accepts in concept Boise’s adjustment to reduce wheeling expenses related to BPA NT Service,” but he testifies that Boise White Paper’s proposed calculations are flawed and overstate the required adjustment.¹³⁰ Mr. Duvall characterizes Boise White Paper’s proposed adjustment as overly complicated resulting in a forecasted wheeling expense forecast that is less than 2013 actual levels. This result, he suggests, is particularly unreasonable considering a 2013 BPA rate increase.
- 93 The Company proposes “a straightforward and reasonable” alternative adjustment to reduce NT Service wheeling expense. Mr. Duvall proposes to calculate the NT Service expense based on the historical 2013 expenses, adjusted to account for the October 2013 rate increase.¹³¹ This adjustment results in a reduction to WCA NPC of \$0.8 million.
- 94 *Commission Determination:* The Company’s approach is at least straightforward and we consider it reasonable for purposes of this case.¹³² The record demonstrates, however, that it may be possible to calculate these costs with greater accuracy based on BPA’s OATT and actual experience during the test year. We expect to see these costs supported by a more refined approach in the Company’s next case.

5. Inter-Hour Wind and Load Integration Costs

- 95 The Company proposes in its direct case to refine its forecasting of NPC in the GRID model by utilizing actual 2012 wind energy output data from the Company’s owned and purchased wind facilities shaping hourly wind generation profiles.¹³³ According to Mr. Duvall, this refinement improves the accuracy of its NPC forecast by using recent wind data to develop profiles which better capture the hourly volatility of wind generation. Mr. Duvall provides a detailed technical discussion in his testimony and states that the Company has tested this refinement using method developed in a

¹³⁰ Duvall, Exh. No. GND-4T at 65:2-7.

¹³¹ *Id.* at 66:1-8.

¹³² *Id.* at 65:9-15.

¹³³ *See generally* Duvall, Exh. No. GND-1CT at 26:3-29:9.

technical report published by the National Renewable Energy Laboratory (NREL).¹³⁴
Mr. Duval testifies that:

In its study, NREL calculated the coefficient of variation (COV), defined as the ratio of standard deviation value to plant nameplate capacity, to gauge the short-term variability of wind generation. The Company applied this same calculation on four of its wind resources located in the west control area.¹³⁵

Mr. Duvall says the results show that the COV of the Pacific Power wind plants is fairly consistent over time and that the variability in the Company's revised modeling is much closer to the historical levels.¹³⁶

96 Boise witness Mr. Mullins testifies that by including the newly proposed hourly wind shaping methodology, a similar integration costs *pro forma* adjustment by the Company outside of the GRID model should be removed.¹³⁷ He claims that with the change in the GRID model proposed by the Company, these inter-hour wind and load integration costs are now being double-counted within the model and the *pro forma* charge outside the model.

97 Mr. Duvall maintains in his rebuttal testimony that inter-hour integration of load and wind resources is appropriately reflected in the Company's NPC and is not duplicated by modeling load and wind profiles on an hourly basis. He testifies that Mr. Mullins basic assumption that system-balancing wind integration costs and system costs associated with the hour-to-hour variability in wind output are the same is flawed. The increase in NPC due to wind variability is not the same as inter-hour integration cost and both must be recognized.¹³⁸ Mr. Duvall says that wind variability is addressed within the GRID model using the proposed wind shaping data. The Company uses the results of the model to commit generation resources based on the model's forecasted load and wind generation. Wind inter-hour integration costs, on

¹³⁴ Y. H. Wan, *Long-Term Wind Power Variability*. Technical Report, NREL/TP-5500-53637 (Jan. 2012). Available online at <http://www.nrel.gov/docs/fy12osti/53637.pdf>.

¹³⁵ Duvall, Exh. No. GND-1CT at 28:16-29:2.

¹³⁶ *Id.* at 29:3-29:9.

¹³⁷ Mullins, Exh. No. BGM-1CTr at 46:18-47:9.

¹³⁸ *See generally* Duvall, Exh. No. GND-4T at 48:18-51:15.

the other hand, reflect charges associated the costs of balancing around the actual wind output and load. According to Mr. Duvall, it is appropriate to reflect both in the Company's cost of service.

98 Boise White Paper also argues that the wind inter-hour integration costs is a new charge that has neither been included in prior filings nor documented as a modeling change in this filing.¹³⁹ Mr. Duvall responds to this by pointing out that the charge was reflected in the prior 2010 Wind Integration Study, which reflected the combined load and wind integration costs.¹⁴⁰ The 2010 Wind Integration Study was used in Docket UE-111190 reflecting in rates the costs for inter-hour integration costs for load.¹⁴¹ In the new 2012 study, responding to stakeholders, the costs were broken into Wind and Load related costs.

99 *Commission Determination:* We decline to accept Boise White Paper's proposed inter-hour wind and load integration adjustment. The Company describes in detail its system of modeling and its two-step process from forecast to actual, thereby explaining what it portrays as a misconception by Mr. Mullins. Pacific Power demonstrates convincingly that it has not double-counted costs or otherwise reflected the same wind integration adjustment using two different approaches. We reject Boise White Paper's recommendation that we require removal of the Company's outside-of-GRID *pro forma* adjustment of wind integration costs.

6. Chehalis Outage

100 In November 2013, one of the three generation units at Chehalis experienced an outage caused by the failure of a step-up transformer. Boise White Paper recommends that the Commission exclude the 2013 Chehalis outage from GRID model outage rate calculations because the outage: 1) is not representative of normal plant operations in the rate period; and 2) resulted from imprudent operation.¹⁴²

101 Pacific Power points out that in the Company's 2010 rate case, Boise White Paper's NPC witness through its trade group, the Industrial Customers of Northwest Utilities

¹³⁹ Mullins, Exh. No. BGM-1CTr at 49:6-16.

¹⁴⁰ Duvall, Exh. No. GND-4T at 51:4-15.

¹⁴¹ *Id.*

¹⁴² Mullins, Exh. No. BGM-1CTr at 50:13-15.

(ICNU), testified that an outage should be excluded as anomalous only if it exceeds 28 days.¹⁴³ Since the Chehalis outage was less than 28 days, Pacific Power reasons it is within the realm of “normal.”¹⁴⁴ What the Commission determined in Pacific Power’s 2010 GRC, however, is that

The dispute before us is how to set an annual outage rate in light of a single, large, anomalous event. We agree with Staff that the purpose of establishing an annual outage rate is to represent expected outage levels during the rate year. PacifiCorp does not dispute that the approximately seven month outage is an anomaly. *ICNU’s proposal to remove all outages longer than 28 days addresses the issue, but lacks substantial justification.*¹⁴⁵

The Commission’s rejection of a proposed standard should not be cited as basis for drawing the inference Pacific Power urges us to make. Moreover, Boise White Paper says it recommends the exclusion of the 2013 Chehalis outage not on the basis of its duration, but because it was the third catastrophic outage within a decade, all due to the same transformer bushing design failure.¹⁴⁶

102 Boise White Paper’s principal argument, in any event, is that the outage was the result of imprudence because the plant had experienced similar types of outages in prior years, one in 2006 and one in 2011.¹⁴⁷ Mr. Mullins includes in his largely confidential testimony on this issue a discussion of the root cause analysis from which he infers imprudence. Mr. Ralston, who has 28 years of experience in plant operations and maintenance and is responsible for the operation and maintenance of the PacifiCorp generation fleet, testified on rebuttal that the plant was operated consistent with standard industry practices, that the Company’s actions following the 2011 outage were reasonable, and that the two prior outages would not have caused

¹⁴³ Pacific Power Initial Brief ¶ 114 (citing *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 139 (Mar. 25, 2011)).

¹⁴⁴ Mullins, Exh. No. BGM-1CT 50:11-13.

¹⁴⁵ *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 141 (March 25, 2011) (emphasis added).

¹⁴⁶ Boise White Paper Reply Brief ¶ 55.

¹⁴⁷ Pacific Power did not own the Chehalis plant in 2006.

the Company to operate the plant differently.¹⁴⁸ In fact, following the 2011 outage, the Company installed monitoring equipment on the generator step-up transformers specifically to allow the Company to assess the risk of future failures—an action that exceeds standard industry practice.¹⁴⁹

103 Pacific Power, again relying on Mr. Ralston’s testimony, also disputes Boise White Paper’s claims that in the month leading up to the 2013 failure, the monitoring equipment indicated a problem and that it was “very clear” that the Company was “operating [the plant] in alarm status for a very long period of time.”¹⁵⁰ The Company says that “[w]henver the data indicated an abnormality, the Company took immediate action to determine whether remedial steps were necessary, including the removal of the unit from service.”¹⁵¹ Mr. Ralston testifies in this connection that:

Whenever the data indicated that abnormal conditions were present, it was immediately reported to Chehalis plant personnel from the bushing monitoring equipment. When the Company received abnormal condition notices, the Company contacted the OEM to determine if the abnormal condition warranted action by the Company, such as removal of the transformer from service. In one instance, the Company discovered that the OEM had incorrectly commissioned the equipment. This issue was corrected before the 2013 failure.¹⁵²

104 *Commission Determination:* The focus of Mr. Mullins’ testimony for Boise White Paper on this issue is not the duration of the Chehalis outage, but rather on his belief that the repeated and “catastrophic” nature of the event marks it as abnormal. The weight of the evidence concerning imprudence on the part of plant operators favors the Company’s argument that it was not such operation on the part of Pacific Power that led to this outage. On balance, we are not persuaded by Boise White Paper’s argument and will not require the Company to remove this outage from GRID model outage rate calculations used in determining NPC in this case.

¹⁴⁸ Pacific Power Initial Brief ¶ 116 (citing Ralston, Exh. No. DMR-2T at 4:20-5:5, 6:5-16, 6:21-7:22, 8:1-10).

¹⁴⁹ *Id.* (citing Ralston, Exh. No. DMR-2T at 4:18-5:5, 6:11-12).

¹⁵⁰ *Id.* ¶ 117 (quoting Mullins, TR. 750:2-751:4).

¹⁵¹ *Id.*

¹⁵² Ralston, Exh. No. DMR-2T at 5:6-21.

D. PCAM

105 Pacific Power sought approval of a PCAM in its 2006/2007 GRC, arguing that implementation of such a mechanism was justified by the facts that the Company faced volatility in net power costs and because Avista and PSE have power cost adjustment mechanisms.¹⁵³ The Commission found that:

PacifiCorp's circumstances include significant exposure to variability in power costs and this variability is sufficient to justify a PCAM. However, PacifiCorp has designed its mechanism on the basis of the PCAM we approved for Avista, the so-called ERM, without making refinements that our record shows are appropriate in light of PacifiCorp's unique circumstances. Specifically, we find that the design features proposed by the Company and modified by Staff do not appropriately balance risk and benefits. There are two principal reasons:

- The accounting for actual and computer-generated-actual costs has not been shown to be reliable.
- The design of the dead band and sharing bands should reflect the asymmetry of power cost risk that is evident in PacifiCorp's case.¹⁵⁴

The Commission expressed its receptiveness to a properly designed PCAM for Pacific Power and expressly invited the Company to file a petition within 12 months after Order 08, outside of a general rate case, "seeking approval of a PCAM

¹⁵³ See *WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.*, Docket UE-061546, Order 08 ¶ 59 (June 21, 2007). This was the Company's second request for approval of a PCAM. The first came in Pacific Power's 2005/2006 GRC, Docket UE-050684. The Commission rejected the Company's tariff filing, including the PCAM proposal, based on its reliance on the Revised Protocol method for inter-jurisdictional cost allocation, which the Commission rejected as inappropriate for the determination of rates in Washington. See *WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.*, Docket UE-050684, Order 04 (April 17, 2006). Order 04 includes discussion about the Company's PCAM proposal and offered guidance for a future filing, including the Commission's requirement for appropriate dead bands and sharing bands.

¹⁵⁴ *WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.*, Docket UE-061546, Order 08 ¶ 59 (June 21, 2007); see also *Id.* ¶¶ 83-87.

consistent with the guidance we provide here and with or without a request for authority to file power cost only rate cases (PCORCs).”¹⁵⁵

106 Pacific Power did not accept the Commission’s invitation to file for authority to implement a PCAM outside of a general rate case. Nor did the Company ask for such authority in its GRC filings in 2008, 2009, 2010, or 2011.

107 Pacific Power filed its third PCAM proposal as part of its 2012 GRC.¹⁵⁶ The Commission rejected the proposal in light of the Company’s failure to design it following “the explicit direction the Commission” gave Pacific Power in the earlier cases. The Commission determined that:

[T]he Company’s proposal here is even more at odds with the direction the Commission has given PacifiCorp than its proposals in prior cases that have been rejected. Contrary to express Commission direction, and in contrast to the power cost adjustment mechanisms approved in other PacifiCorp jurisdictions, the Company’s proposal here includes neither dead bands nor sharing bands. These are critically important elements that provide an incentive for the Company to manage carefully its power costs and that protect ratepayers in the event of extraordinary power cost excursions that are beyond the Company’s ability to control.¹⁵⁷

The Commission’s order in Docket UE-130043 includes a detailed critique of Pacific Power’s arguments¹⁵⁸ and concludes:

What PacifiCorp proposes here does not include any of the specific design elements the Commission has identified in its prior orders. Like

¹⁵⁵ *Id.* ¶ 60.

¹⁵⁶ *See Utilities & Transp. Comm’n v. PacifiCorp d/b/a Pacific Power & Light*, Docket UE-130043, Order 05 (December 4, 2013). The Company filed its first PCAM proposal in 2005. *See WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.*, Docket UE-050684, Order 04 (April 17, 2006), and its second a year later, in 2006. *See WUTC v. PacifiCorp d/b/a Pacific Power and Light Co.*, Docket UE-061546, Order 08 (June 21, 2007).

¹⁵⁷ *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-130043, Order 05 ¶ 170.

¹⁵⁸ *Id.* ¶¶ 171-72.

Staff, we are open to consider a properly designed PCAM proposal that incorporates the appropriate balance between the Company and ratepayers. Yet, the Company's proposal in this case really is nothing more than a request for a power cost tracker and true-up mechanism that will guarantee the Company full recovery of its power costs on a continuing basis. We are not prepared to embrace such a mechanism and, therefore, reject PacifiCorp's proposed PCAM.¹⁵⁹

108 The Company elected in this case not to file "a properly designed PCAM proposal that incorporates the appropriate balance between the Company and ratepayers." Instead, Pacific Power filed another tracker mechanism, a so-called Renewable Resource Tracking Mechanism (RRTM), providing a dollar-for-dollar annual true-up between forecast and actual power costs for the Company's renewable resource generation. We discuss below several of the fundamental failings of this proposal that give us independent reasons to reject it. Also important to our decision to reject the RRTM, however, is Commission Staff's interest in effecting a broader solution to address the Company's challenges in terms of power cost recovery.

109 To this end, Mr. Gomez testifies to Staff's belief that "the Commission has provided more than sufficient guidance to Staff and the Company over the last nine-years on this issue to warrant action and to move forward with implementation of a PCAM once and for all."¹⁶⁰ Mr. Gomez, focusing on the Commission's detailed discussion of a PCAM proposed in Pacific Power's 2006 GRC,¹⁶¹ addresses the key factors that led the Commission to reject Pacific Power's proposal and explains Staff's view of the appropriate means to address these issues in this case.

110 Mr. Gomez first discusses the Commission's concern relative to the Company's proposed use of a computer-generated cost methodology to determine both forecasted normalized base power costs and to determine "actual costs" that would be trued-up on an annual basis. In this regard, the Commission discussed in Order 08 that:

Base power costs are a statistical estimation of what level of costs is expected under normal conditions. Because this is an estimate, it is not expected to match the actual costs incurred in any given year. The core

¹⁵⁹ *Id.* ¶ 173.

¹⁶⁰ Gomez, Exh. No. DCG-1CT at 19:13-16.

¹⁶¹ *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶¶ 59-111 (June 21, 2007).

idea of a power cost adjustment mechanism is to true-up these estimated costs with actual costs that are the measured and documented costs that did occur in a given year.

Our concern is that the computer-generated, pseudo-actual costs will themselves be only estimates including some statistical (i.e., modeling) variability (i.e., error). The Company and Staff contend that actual data, rather than assumptions, will be used in the computer model. Presumably that will reduce the modeling error and produce a more precise result. Truing-up one estimate with another more precise estimate may be justified, but the risk is that neither will be accurate and using two inaccurate, even if precise, estimates of cost to set cost-based rates could lead us to depart farther and farther from actual costs. A key problem with this approach is that we would never know.¹⁶²

111 Mr. Gomez testifies that in Docket UE-130043, the Company's 2012/2013 GRC, Pacific Power abandoned its prior proposal that relied on computer-generated costs and, instead, offered to report actual NPC per its books and records. In Staff's view, "[t]his approach resolves the first threshold hurdle to a properly designed PCAM for Pacific Power."¹⁶³

112 Turning to the issue of dead bands and sharing bands, Mr. Gomez testifies that Staff's proposal would resolve the second point of concern stated in Order 08 by proposing a PCAM with properly designed sharing and dead bands. In the earlier case, the Commission included in Order 08 at Table 2, reproduced here, showing the parties' respective proposals for dead bands and sharing bands in the 2006/2007 time frame:

¹⁶² *Id.* ¶¶ 76-77.

¹⁶³ Gomez, Exh. No. DCG-1CT at 20:13-14.

PCAM Proposals¹⁶⁴

	Dead Band	Sharing Bands	Other Features	Risk-Adjustment
PacifiCorp	+/- \$3 M	+/- \$3- 7.4M 60% customer >\$7.4M 90% customer	Include fixed cost for new resources \leq 50 MW for \leq 2-year term; Retail Load Adjustment; \$3 M threshold for cost-recovery.	None
Staff	+/- \$4M	+/- \$4 – 10M 50% customer >\$10M 90% customer	No fixed cost for new resources (only variable cost); Retail Load Adjustment; \$6 M threshold for cost-recovery.	Reduction in equity component of capital structure to 42% [ROR = 7.90]
ICNU	+/- \$8.6 M	+/- \$8.6 – 17.3M 50% customer > \$17.3 85% customer	No other detail	ROE reduction of 30 basis points [ROR = 7.92]

The Commission expressed its concern that none of these proposals reflected the asymmetry in the distribution of net power costs that “skewed [them] toward higher costs, in part because poor hydropower is correlated with higher wholesale power costs and higher fuel costs.”¹⁶⁵ Order 08 states that:

An optimally designed PCAM would recognize the inequality between upside and downside risk in its design of deadbands and sharing bands. For example, to equally balance risk with benefit, the deadband and sharing bands should be set at lower levels on the “lower cost” side of base costs to increase the expected value of customer benefits enough

¹⁶⁴ *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 66 (June 21, 2007).

¹⁶⁵ *Id.* ¶ 85.

to balance the expected value of customer risks on the “high side” of base costs.¹⁶⁶

113 Staff proposes in this case a dead band of plus or minus \$25 million on a WCA basis which corresponds to about 5 percent of the average NPC costs for the Company on a WCA basis. How Staff determines this level on a WCA basis is unclear. It is also not clear why, unlike Staff’s recommendation in Pacific Power’s 2006/2007 GRC, this is not reduced to a Washington basis that would allow for comparison to earlier proposals.

114 As to the sharing bands Staff proposes in this case:

[A]ny remaining portion of the variance above or below the dead-band will be shared with customers in different proportions depending if the variance between base and actual NPC reflects a year-end surcharge or rebate. Under-recovery of NPC (that is, in the surcharge direction) will be shared on a 50/50 basis between customers and the Company. To reflect asymmetry of power cost distribution, over-recovery of NPC (that is, in the rebate direction) is shared by 75 percent going to customers and the remainder retained by the Company.¹⁶⁷

Mr. Gomez illustrates the operation of these proposed bands in a confidential exhibit using “actual NPC results provided by the Company in the last rate case [in Docket UE-130043,] which were updated with results from 2012 and 2013.”¹⁶⁸ Again, however, Staff does not explain the bases for its choice of a single sharing band or the degree of asymmetry reflected in the sharing mechanism it proposes.

115 In considering the types of costs that would be included in Staff’s proposed PCAM, Mr. Gomez testifies that Staff accepts the approach proposed by Pacific Power in its 2012/2013 GRC. That is, the PCAM is calculated “using all components of NPC as traditionally defined in the Company’s general rate cases and modeled by the Company’s GRID model.”¹⁶⁹ Mr. Gomez provides details in his testimony

¹⁶⁶ *Id.* ¶ 86.

¹⁶⁷ Gomez, Exh. No. DCG-1CT at 22:16-22.

¹⁶⁸ *Id.* at 20:15-20 (referring to Exh. No. DCG-5C).

¹⁶⁹ *Id.* at 21:3-5.

identifying the specific FERC accounts that are included.¹⁷⁰ Thus, Mr. Gomez testifies, “the proposed PCAM for PacifiCorp will be very similar to Avista Corporation’s Energy Recovery Mechanism (ERM),”¹⁷¹ on which the Company based its own proposal in the 2006/2007 GRC.

- 116 Also like the Avista ERM, Staff’s proposed PCAM will include a monthly retail revenue adjustment applied to the monthly difference between actual NPC and forecasted base NPC. The retail revenue adjustment will reflect the power production expenses recovered through base retail revenues due to changes in retail load, as follows:

Base NPC will be divided by the base load MWh to arrive at a net power cost sales factor (SF) expressed in dollars per MWh. The monthly retail revenue adjustment used in the PCAM will be computed by multiplying the SF by the difference between actual and base monthly retail MWh sales. If actual MWh sales are greater than base, the retail revenue adjustment will reduce the PCAM deferral. If actual MWh sales are less than base, the retail revenue adjustment will increase the PCAM deferral.¹⁷²

- 117 Staff proposes a carrying charge on the customers’ share of NPC deferral balances using the Company’s actual cost of debt. This is to be updated semi-annually and applied to NPC deferral balances less associated accumulated deferred income taxes. Staff would require the Company to report semi-annually the result of the updates to the parties in this proceeding. Interest would be accrued monthly and compounded semi-annually.¹⁷³
- 118 The deferrals will trigger a rate adjustment when the customers’ share of Washington-allocated NPC deferrals accumulates to 10 percent of base retail revenues. If this happens, Pacific Power will file to implement a surcharge or rebate through a separate tariff schedule dedicated to this purpose. The proposed effective date of the tariff must allow for a 90-day review and approval process. The Company may propose a

¹⁷⁰ *Id.* at 21:5-16.

¹⁷¹ *Id.* at 21:17-19.

¹⁷² *Id.* at 22:1-10.

¹⁷³ *Id.* at 23:5-10.

different effective date, subject to Commission approval, to minimize the number of rate changes to customers.¹⁷⁴

- 119 Any surcharge or rebate will be spread to rate schedules on the same basis as power costs are allocated using base revenues approved in this proceeding, unless otherwise changed in a future rate proceeding. Within each rate schedule the rate adjustment will apply to the energy charges on a uniform cents per kilowatt-hour basis using the most recent normalized kilowatt-hours as filed annually by the Company pursuant to Commission Basis Reporting requirements. There is an exception for street and area light rates, which will be adjusted by a uniform percentage. The rate adjustment will be in effect for a 12-month period and only one surcharge or rebate will be in place at any given time.¹⁷⁵
- 120 Finally, Staff proposes that the Company be required to file quarterly reports of activity in the PCAM when it files its quarterly report of actual operations. In addition, the Company will file annually, on or before April 1st of each year, its PCAM deferrals from the previous calendar year. Standard discovery rules will apply for Company responses to data requests allowing the Commission Staff and interested parties the opportunity to review the deferral information during a 90-day review period ending June 30th of each year. The 90-day review period may be extended by agreement of the parties participating in the review, or by Commission order. The Commission will be asked to confirm and approve the deferral balances in an open meeting or to conduct appropriate process if they are challenged.
- 121 *Commission Determination:* We agree with Pacific Power's repeated assertions over the past 10 years that it should have a power cost adjustment mechanism in place to address higher than normal variability in its net power costs, just as do the other electric power utilities subject to the Commission's jurisdiction, PSE¹⁷⁶ and Avista.¹⁷⁷ However, the Company has yet to come forward with a proposal that includes the properly designed elements the Commission has clearly said it requires. This is no longer acceptable, especially considering the clear, repeated discussion by the Commission in prior orders concerning the minimum requirements for a PCAM.

¹⁷⁴ *Id.* at 23:13-19.

¹⁷⁵ *Id.* at 23:20-24:5.

¹⁷⁶ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-011570 and UG-011571, Twelfth Supp. Order (June 20, 2002).

¹⁷⁷ *WUTC v. Avista Corporation*, Docket UE-011595, Fifth Supp. Order (June 18, 2002).

Thus, as we discuss in more detail below, we will begin an expedited proceeding within 30 days of entering this Order to develop and implement a full PCAM for Pacific Power consistent with the Commission's direction in prior orders. We expect to complete the proceeding, resulting in a tariff filing by Pacific Power, no later than May 31, 2015.

122 We note that Staff's proposal in this case is well-grounded in precedent, modeled both to be consistent with the ERM the Commission approved for Avista in 2002 and to reflect the guidance the Commission has provided specifically to Pacific Power in earlier cases. Indeed, Staff's effort appears to have been guided to a large degree by Pacific Power's 2006/2007 PCAM proposal, which was based on Avista's ERM, as well as the Commission's discussion of that proposal's failure to reflect circumstances specific to Pacific Power, including issues related to power cost measurement and asymmetry in the distribution of power costs. We commend Staff for proposing such a model.

123 Despite Staff's efforts to craft a well-balanced proposal that conforms to previous guidance from the Commission, we find the record should be developed further with respect to a number of questions including, for example:

- Is it appropriate to use the WCA as the jurisdictional divide for wholesale power costs?
- Is \$25 million the appropriate dead band and how did Staff determine this amount?
- Does \$25 million reflect normalized variability in power costs?
- How exactly did Staff arrive at its recommendation for a 50/50 sharing between the Company and its customers for under recoveries of NPC that exceed the dead band and a 25/75 sharing for over recoveries, in favor of customers?

124 Given these needs to supplement our record we will conduct further proceedings to identify and resolve the details of designing fully and implementing a PCAM mechanism for Pacific Power. Thus, we will set by separate notice a date for a prehearing conference within 30 days following the entry of this Order to establish a procedural schedule to develop the details we find, and others may suggest, are necessary to implement fully the PCAM we determine is required for Pacific Power. The prehearing conference also will provide a forum for further discussion of what

issues require additional development. Finally, the prehearing conference will provide an opportunity to explore the potential for early settlement discussions among the parties, which the Commission strongly encourages.

- 125 We direct our questions above to Staff, considering that the Company did not file a full PCAM in this case, and that other parties complain of having too little time to contribute meaningfully to the development of such a tool. However, we invite the Company and others who have an interest to bring their own ideas to our attention with detailed explanation and support. We can then tailor a PCAM to the unique characteristics of Pacific Power taking into account a range of well-supported ideas.
- 126 We believe some additional time is necessary, however, we do not believe that this will require a great deal since these concepts have been discussed in detail for nearly 10 years. We will require Pacific Power to file tariff sheets necessary and adequate to implement a Power Cost Adjustment Mechanism no later than May 31, 2015. If no full-party agreement can be reached by that time, or the Company declines by that date to file a full PCAM consistent with prior Commission orders, we will approve expeditiously a mechanism generally along the lines Staff proposes in this docket.
- 127 Furthermore, we take this opportunity to reiterate that there is no barrier to the Company filing for approval of a PCORC mechanism, if the Company perceives it to be necessary and appropriate to resolve issues related to the detailed PCAM design.¹⁷⁸

¹⁷⁸ See Docket UE-061546, Order 08 ¶ 82, which we find worthy of quotation as a means to provide guidance to Pacific Power, and others, with respect to the basis for our thinking vis-à-vis a potential PCORC filing:

The Company and Staff agree that the variable cost of new resources less than 50 MW and with a term less than 2-years should be included in the PCAM, but disagree on whether fixed costs should be included. The Company argues that including these fixed costs is necessary to accommodate its need to acquire renewable resources in the future to comply with Washington's Renewable Portfolio Standard.¹⁷⁸ PacifiCorp agrees to exclude these fixed costs from the PCAM, however, if the Commission authorizes it to file for approval of PCORC mechanism that accommodates an annual adjustment.¹⁷⁸ In general, we find it appropriate to include in the PCAM the variable costs of smaller, short-term resource additions, but to exclude the fixed costs. There has never been any barrier to the Company filing for approval of a PCORC mechanism. Indeed, it could have done so in this docket, but did not raise the idea until late in the proceeding. Even then, the Company did not make a specific, detailed proposal.

The Company may do so either as part of a settlement agreement in the subsequent phase of this docket, or by means of a separate filing of a unilateral proposal by Pacific Power to which Staff and other interested persons may respond.

E. Renewable Resource Tracking Mechanism (RRTM)

128 As discussed above, Pacific Power proposes in this case a power cost tracker mechanism providing a dollar-for-dollar true-up between forecast and actual power costs on an annual basis that is principally different from its proposal in Docket UE-130043 only because it would track just a part of the Company's power portfolio instead of the full portfolio. Mr. Duvall identifies the mechanism "as a more narrowly tailored mechanism," a Renewable Resource Tracking Mechanism (RRTM) limited to "resources eligible for the renewable portfolio standard (RPS) included in Washington rates."¹⁷⁹ As Mr. Twitchell testifies for Staff:

While narrower in scope, the RRTM would operate by the same mechanism proposed for the PCAM in 2013. Both proposals would true up projected costs to actual costs and recover any negative differential from ratepayers. If a positive differential exists, then this amount would be returned to ratepayers. The RRTM's reduced scope does not mean that it is not a PCAM; rather, the reduced scope makes it an improperly designed PCAM.¹⁸⁰

129 The Company's principal argument in support of the RRTM is that it:

[F]urther Washington state energy policy and promotes renewable development by mitigating the cost-recovery concerns that arise due to the inherent variability of many renewable resources. By allowing full cost recovery of RPS-eligible resources, the RRTM is consistent with the cost-recovery provision of the EIA, which entitles utilities to

The Commission will certainly give any such proposal fair consideration if and when filed.

¹⁷⁹ Pacific Power Initial Brief ¶¶ 104-05 (citing Duvall, Exh. No. GND-1CT at 38:5-18).

¹⁸⁰ Twitchell, Exh. No. JBT-1T at 7:3-8.

‘recover all prudently incurred costs associated with compliance’ with the RPS.¹⁸¹

Pacific Power argues in addition that because “RPS-eligible resources are largely intermittent” the proposed mechanism “focuses on resources that exhibit significant variability outside the Company’s control.”¹⁸²

130 Mr. Mullins testifies for Boise White Paper, however, that the annual variability of Pacific Power’s RPS resource output has remained relatively stable in recent years, with the relative standard deviation of wind output at only about 6 percent.¹⁸³ This is a relatively small to moderate degree of variability and is significantly less variability than experienced by the Company, for example, with its hydropower resources, which have demonstrated a relative standard deviation of 14 percent.¹⁸⁴ Staff argues in this connection, too, that a power cost recovery mechanism including only part of a company’s total power costs fails to recognize that “[t]he financial performance of a company’s *entire* generation portfolio is what determines whether a company has under- or over-recovered its power costs.”¹⁸⁵ Moreover, Pacific Power has a diverse generation fleet, including coal, natural gas, hydropower, and wind resources, all of which exhibit some degree of variability.¹⁸⁶

131 In point of fact, Pacific Power’s generation fleet is, or should be, deployed following principles of economic dispatch. Related to this point, Mr. Twitchell testifies that:

By segregating wind resources for special cost treatment, the Company ignores the real chance that reduced costs in other areas of its generator portfolio could more than offset any difference between the wind energy costs determined by its NPC model and in-period actuals.¹⁸⁷

¹⁸¹ Pacific Power Initial Brief ¶ 105 (internal citations omitted).

¹⁸² *Id.* ¶ 106.

¹⁸³ Mullins, Exh. No. BGM-1CT at 53:19-54:3.

¹⁸⁴ *Id.* at 55:4-56:5.

¹⁸⁵ Staff Initial Brief ¶ 101.

¹⁸⁶ *Id.* ¶ 102.

¹⁸⁷ Twitchell, Exh. No. JBT-1T at 13:12-15.

Likewise, Mr. Mullins testifies that the Company's diverse portfolio is what matters. The RRTM's attempt to isolate cost recovery of certain generators "ignores the fact that [the Company's] overall system is benefiting as a result of the diverse nature of all the resources in its portfolio."¹⁸⁸ Staff concludes its contribution to this line of argument with the observation that:

[T]he RRTM's focus on single characteristic resources is too narrow and fails to consider what really matters – the cost performance of the Company's entire resource portfolio and market purchase activities. The hypothetical costs offered by the RRTM should be rejected in favor of a full PCAM as proposed by Mr. Gomez.¹⁸⁹

132 *Commission Determination:* We reject the Company's request for a "renewable tracker" for the reasons below and in light of our determination above to require Pacific Power to implement a properly designed PCAM in this case. Albeit limited in scope to only a part of Pacific Power's power portfolio, the RRTM unquestionably is a form of PCAM. Yet, again, the Company elects not to follow the straightforward direction the Commission has given it concerning the required elements for properly designed PCAM, instead proposing again a dollar-for-dollar tracker. Pacific Power fails to recognize that the "appropriate balance" to which the Commission refers in Order 05, and recognized in the Company's Initial Brief,¹⁹⁰ refers to the Commission's insistence on properly designed dead bands and sharing bands in any PCAM. Pacific Power purports to have addressed the Commission's requirement for balance by proposing "a more narrowly tailored mechanism in this case, the RRTM."¹⁹¹ The reduced scope of this power cost tracking mechanism that has no dead bands or sharing bands, however, misses the mark.

133 Pacific Power's failure, once again, to follow the plain direction the Commission offers in its orders with regard to the requirements for an acceptable power cost recovery mechanism is reason enough for us to reject the RRTM. Pacific Power may continue to be of the opinion that "dead bands and sharing bands are poor regulatory

¹⁸⁸ Mullins, Exh. No. BGM-1CT at 57:21-22 and 58:1-2.

¹⁸⁹ Staff Initial Brief ¶ 104.

¹⁹⁰ Pacific Power Initial Brief ¶ 104.

¹⁹¹ *Id.*

policy,” as Mr. Duvall testified in Docket UE-130043.¹⁹² The Company, however, cannot expect success with any power cost recovery mechanism proposed in Washington that ignores the fact that requiring such bands in PCAMs *is* the regulatory policy of this Commission. We note that Pacific Power recognizes this policy in other states in which the Company does business and has a power recovery mechanism in place, because the mechanisms approved by the regulatory authorities in those states all have dead bands, sharing bands, or both.¹⁹³

134 Pacific Power’s effort to tie approval of its RRTM proposal to the Energy Independence Act and its RPS is far wide of the mark. There is nothing in the Act that requires approval of a power cost tracker to ensure that a company recovers its prudently incurred costs of complying with the RPS.

135 Another flaw in the RRTM is that it ignores the performance of Pacific Power’s diverse portfolio of resources. Without considering the financial performance of Pacific Power’s entire generation portfolio it is not possible to determine whether the Company under-recovers or over-recovers its power costs during any given period. In the final analysis, we agree with Staff that the Company’s RRTM proposal should be rejected in favor of a full PCAM that is designed to take into account the cost performance of the Company’s entire resource portfolio and market purchase activities, that appropriately balances risks between the Company and its customers, and that provides Pacific Power with a continuing incentive to focus on managing its power resources rather than arguing repeatedly that it is beyond its ability to do so.¹⁹⁴

¹⁹² See Docket UE-130043, Order 05 ¶ 164 (citing and quoting in part Duvall, Exh. No. GND-1CT at 31:20-32:5).

¹⁹³ California is the only exception. See TR 391:16-392:3 (Cross-examination of Mr. Dalley by Ms. Davison for Boise White Paper).

¹⁹⁴ We note that both PSE and Avista seem to have little difficulty managing their power portfolios and power costs operating similarly diverse portfolios of power sources in the same power markets, under the same RPS standards, and subject to the same Integrated Resource Planning requirements as apply to Pacific Power in Washington. Both have power cost recovery mechanisms that have been in place for some years and that have worked quite satisfactorily over the term of their operation.

F. Rate Base Assets and Depreciation

1. End of Period Rate Base (Adjustments 8.12 – 8.12.6); Depreciation and Amortization Reserve Adjusted to December 2013 (Adjustments 6.2 - 6.2.2)

- 136 These proposed adjustments work in tandem. Company Adjustments 8.12 – 8.12.6 “walk forward” plant balances from December 2013 average of monthly averages (AMA) rate base to December 2013 year-end adding \$22,392,711 to rate base using end-of-period (EOP) balances.¹⁹⁵ The associated accumulated reserve impacts are accounted for in Adjustments 6.2 – 6.2.2. The proposed adjustments reduce rate base by \$17,976,136,¹⁹⁶ resulting in a net increase in rate base of \$4,416,575 using the EOP measurement instead of AMA balances for the test year.
- 137 The record on this issue is sparse, at best. In the Company’s direct case, it consists of a single Q&A in Mr. Dalley’s testimony:

Q. Please describe the Company’s proposal for the use of end-of-period rate base balances?

A. Consistent with the 2013 Rate Case, the Company proposes to reflect electric-plant-in-service balances at end-of-period levels rather than on an average-of-monthly-averages basis. As discussed in more detail in the direct testimony of Ms. Siores, the Commission has recognized in multiple proceedings that use of end-of-period rate base mitigates regulatory lag. For example, in the 2013 Rate Case, the Commission concluded: “In this case, there is a need to address at least some of the impacts of regulatory lag on PacifiCorp. We determine

¹⁹⁵ Exh. No. NCS-11 at 1.16, cols. 8.12 – 8.12.6; *see also* Exh. No. NCS-3, Page 8.0.2, ln. 57 (Total).

¹⁹⁶ Exh. No. NCS-11 at 1.11, cols. 6.2 – 6.2.2. We note that this is very significantly different than what the Company originally calculated (*i.e.*, \$6,526,993) and express our concern that no other party apparently audited the Company’s numbers with sufficient care to catch the “formula error” and bring it to our attention in response testimony. Ms. Siores corrects this adjustment to the Company’s depreciation and amortization reserve account in her rebuttal testimony for Pacific Power.

that an appropriate response to address these impacts in this case is approval of PacifiCorp's use of [end-of-period] rate base."¹⁹⁷

138 His reference to Ms. Siores' testimony does not take us to a more detailed discussion of the Commission's recognition "in multiple proceedings that use of end-of-period rate base mitigates regulatory lag." Rather, Ms. Siores' testimony focuses exclusively on describing the two related aspects of the EOP adjustment and observing that this is the same treatment approved in Docket UE-130043:

Depreciation and Amortization Reserve to December 2013 Balance (page 6.2-6.2.2)—This restating adjustment changes the depreciation and amortization reserve from December 2013 AMA balances to actual December 31, 2013 balances. This matches Adjustment 8.12, Plant Balances to December 2013 Balance, as discussed in detail below.

Depreciation Study and Annual Depreciation (page 6.3-6.3.2)—This restating adjustment normalizes depreciation expense and reserve in the historical Test Period to reflect both the impact of the depreciation rates approved by the Commission in Docket UE-130052 and the impact of adjusting plant balances from a December 2013 AMA basis to a year-end December 31, 2013 basis. This treatment is consistent with that approved in the 2013 Rate Case.¹⁹⁸

Plant Balances to December 2013 Balance (page 8.12-8.12.6)—This adjustment modifies the gross plant balances from December 2013 AMA levels to the actual December 31, 2013 ending balances. This adjustment to gross plant balances reduces regulatory lag by reflecting rate base balances at end of Test Period levels. This methodology was approved in the 2013 Rate Case. The associated accumulated reserve and depreciation expense impacts are accounted for in adjustments 6.2 and 6.3, respectively.¹⁹⁹

¹⁹⁷ Order 05 ¶184.

¹⁹⁸ Siores, Exh. No. NCS-1T at 21:13-22:2.

¹⁹⁹ *Id.* at 29:1-7.

- 139 The Company’s rebuttal testimony adds little to this. Mr. Dalley simply observes that Staff and Public Counsel support the use of EOP balances for rate base in this case and that Boise White Paper opposes it because the use of EOP balances “has done little to assuage the frequency of the Company’s rate filings.”²⁰⁰ Mr. Dalley adds that “reflecting rate base using end-of-period balances more accurately reflects the cost to serve customers in the rate-effective period,” and “the Commission’s willingness to use end-of-period rate base balances is an encouraging step that supports future investments.”²⁰¹
- 140 Staff’s Mr. Ball merely recognizes that the Commission approved the use of EOP rate base in Docket UE-130043 and identifies the Company’s adjustments.²⁰² Ms. Ramas, for Public Counsel, testifies similarly that she does not challenge the Company’s use of EOP rate base to address regulatory lag and “hopefully addressing rate case frequency.”²⁰³
- 141 Boise White Paper witness Mr. Mullins opposes the Company’s use of EOP balances. He testifies that:

The use of EOP balances results in a mismatch between revenues, which accrue ratably over the test period, and rate base, which, under the EOP method, is measured at the end of the test period. In addition, the Company’s current practice of almost continuous rate cases mitigates the impact of regulatory lag and the need to deviate from the traditional Commission methodology using AMA rate base balances.

From an accounting perspective, it violates the matching principle to use averages for revenue items, but year-end balances for rate base items. Because revenues accrue ratably over the test year, the rate base, against which operating income is compared, should also reflect the ratable period over which revenues are measured.²⁰⁴

²⁰⁰ Dalley, Exh. No. RBD3-T at 11:4-5 (citing Mullins, Exhibit No. BGM-1T at 17).

²⁰¹ *Id.* at 11:8-15.

²⁰² Ball, Exh. No. JLB-1T at 10:9-13.

²⁰³ Ramas, Exh. No. DMR-1CT at 12:8-13.

²⁰⁴ Mullins, Exh. No. BGM-1T at 16:11-17:2.

Mr. Mullins recommends that the Commission require the Company to use AMA rate base balances when determining revenue requirement in this proceeding.

142 Responding to Staff and Public Counsel in cross-answering testimony, Mr. Mullins testifies that use of EOP balances for rate base is an exception to the historical test period approach and “should not be the normal standard that is used by utilities in their rate filings.”²⁰⁵ He supports the use of AMA methodology because it is true to the matching principle. He cites to the same authority to which Pacific Power points in its brief for the point that “in normal economic times average rate base is more realistic and projects more accurately the cost of plant that produces the revenue under investigation.”²⁰⁶ He says there is no evidence in this record showing that the current economy is “so abnormal as to warrant an exception to the use of AMA.”²⁰⁷

143 Finally, Mr. Mullins testifies that the Commission’s approval of EOP rate base in 2013 apparently did not discourage the Company from “its current pattern of almost continuous rate cases.”²⁰⁸

144 In its Initial Brief, Pacific Power cites to an early case for the proposition that:

The Commission has recognized that the use of EOP rate base is an “appropriate regulatory tool under one or more of the following conditions: (a) abnormal growth in plant; (b) inflation and/or attrition; (c) as a means to reduce regulatory lag; (d) failure of utility to earn its authorized rate of return over an historical period.”²⁰⁹

The Company treats this observation by the Commission over 30 years ago as a standard for approval, arguing that: “Because ‘one or more’ of the Commission’s

²⁰⁵ Mullins, Exh. No. BGM-8T.

²⁰⁶ *Id.* at 9:19-21 (quoting *WUTC v. Wash. Nat. Gas Co.*, Cause No. U-80-111, 44 P.U.R.4th 435 (Sept. 24, 1981)).

²⁰⁷ *Id.* at 9:21-10:2.

²⁰⁸ *Id.* at 10:3-12.

²⁰⁹ Pacific Power Initial Brief ¶ 145 (citing *WUTC v. Wash. Nat. Gas Co.*, Cause No. U-80-111, 44 P.U.R.4th 435, 438 (Sept. 24, 1981); *see also WUTC v. Puget Sound Energy*, Dockets UE-111048, *et al.*, Order 08 ¶ 97 (May 7, 2012)).

conditions has been clearly satisfied in this case, the Commission should approve the use of end-of-period rate base.”²¹⁰

145 *Commission Determination:* We first address Pacific Power’s argument on brief, discussed immediately above, to underscore that the early case to which it cites does not establish a standard for determining when the use of EOP rate base is appropriate. The Commission’s discussion in the first recent case approving this approach provides useful context:

The Commission has traditionally required that utility rates be established relying on the measurement of rate base using the AMA approach. The Commission, however, has occasionally recognized that the alternative approach of utilizing end-of-test period rate base may be appropriate in a variety of circumstances.²¹¹ In a 1981 case, *WUTC v. Washington Natural Gas*, the Commission drew on its early experience evaluating the relative merits of the two approaches and drew the following conclusions:

- (1) Average rate base is the most favored,
- (2) Year-end rate base is an appropriate regulatory tool under one or more of the following conditions:
 - (a) Abnormal growth in plant
 - (b) Inflation and/or attrition
 - (c) As a means to mitigate regulatory lag

²¹⁰ *Id.* ¶ 146.

²¹¹ *See, e.g., WUTC v. Olympic Pipeline Company*, Docket TO-011472, Twentieth Supp. Order, ¶¶ 158-160 and 370 (September 27, 2002). In an earlier case involving PSE’s predecessor on the electric side of its operations, the Commission stated that:

Historically, the commission has accepted the average rate base concept as being an appropriate tool in the measurement of earning levels. It has not, however, discounted the validity of year-end rate base where special conditions exist, such as unusual growth in plant at a faster pace than customer growth and customer rate-making treatment is deficient.

Washington Utilities & Transp. Commission v. Puget Sound Power & Light Co., 7 PUR4th 44, 50 (September 27, 1974). (rejecting end of test period rate base).

(d) Failure of utility to earn its authorized rate of return over an historical period.²¹²

In the PSE cases, the Commission found that all of these “somewhat interrelated” issues were “present to one degree or another” at the point in time when the case was under consideration.²¹³ Importantly, too, the Commission found “ample evidence” of “earnings attrition, caused by continuing growth in capital investments” as important to its consideration of historical under earnings.²¹⁴

146 In this case, we have some evidence of capital additions during relevant periods but it does not demonstrate abnormal growth in plant. Inflation remains very low in the current economic environment in the United States. The Company did not present persuasive evidence that it is suffering attrition in earnings. In particular, the Company did not present an attrition study. Moreover, the fact that the Company failed in the past to earn its authorized return cannot justify use of EOP absent a showing that, due to factors beyond the Company’s control, the Commission can expect this condition to continue into the future. There is no such evidence in the record of this case.

147 The Commission first approved the use of EOP rate base for Pacific Power in 2013, in Docket UE-130043, observing that:

The Commission historically has tolerated some degree of regulatory lag in its ratemaking practice, recognizing that it is a factor in encouraging utilities to operate efficiently. During recent periods, however, the impacts of regulatory lag on the ability of PacifiCorp and other utilities to earn their authorized revenue requirements have contributed to what the Commission has described as a “current pattern of almost continuous rate cases.” Considering this, the Commission stated:

²¹² *Petition of Puget Sound Energy and NWECA for Decoupling Authority*, Dockets UE-12167 and UG-121705 (consolidated) and *WUTC v. Puget Sound Energy*, Dockets UE-130037 and UG-130138 (consolidated), Order 07 ¶ 45 (citing *WUTC v. Wash. Nat. Gas Co.*, 44 P.U.R. 4th 435, 438 (Sept. 24, 1981)).

²¹³ *Id.*

²¹⁴ *Id.* at ¶ 45.

This pattern of one general rate case filing following quickly after the resolution of another is overtaxing the resources of all participants and is wearying to the ratepayers who are confronted with increase after increase. This situation does not well serve the public interest and we encourage the development of thoughtful solutions.²¹⁵

Recognizing the use of EOP rate base as a means to address the problem of regulatory lag having an impact on a utility's ability earn its authorized revenue requirement today, as it last did during the period of extraordinary inflation during the 1970's and early 1980's,²¹⁶ the Commission found in Docket UE-130043 that approval of Pacific Power's use of EOP rate base was an appropriate response.²¹⁷ As the above-quoted passage from Order 05 demonstrates, however, the Commission tied its decision directly to its expectation that granting such relief would discourage Pacific Power from continuing to file one rate case after another, which the Commission found is contrary to the public interest.

148 More importantly, the Commission recognized in Order 05 that the implications of using EOP rate base vis-à-vis the matching principle were not fully developed in the record of Docket UE-103043. The Commission observed, for example, that there should be an adjustment to end-of-period revenues to maintain the integrity of the matching principle. The Commission rejected Public Counsel's proposal for such an adjustment only because:

[I]t would be unduly complicated in the context of this case to fully explore and resolve the impacts that adoption of Public Counsel's

²¹⁵ Docket UE-130043, Order 05 ¶ 181 (quoting *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049 (consolidated), Order 08 ¶ 507 (May 7, 2012)).

²¹⁶ See *WUTC v. Wash. Nat. Gas Co.*, Cause No. U-80-111 44 P.U.R. 4th 435, 437 (Sept. 24, 1981) ("We have in the past decade witnessed a proliferation of rate filings and most filings have brought the differences over rate base into sharp focus.").

²¹⁷ *WUTC v. Puget Sound Energy, Inc.*, Docket UE-130043, Order 05, ¶ 184 (December 4, 2013).

approach would have in terms of the production factor adjustment, allocation issues, and rate spread.²¹⁸

The Commission cautioned, however, that:

In any future case in which PacifiCorp, or another party, proposes EOP rate base, we would expect to see a more fully developed record and a more refined approach to [ensure] there is not a resulting violation of the matching principle.²¹⁹

149 Less than five months after the Commission published these words, Pacific Power filed this general rate case. We observe in this connection that filing rate cases essentially back-to-back means the Commission has no ability to evaluate whether the use of EOP rate base is an improvement over the AMA approach in terms of reducing regulatory lag. If we cannot meaningfully observe some benefit over time to allowing the EOP exception to our preferred approach, we are less inclined to grant the exception.

150 We are most concerned in this case that the record is woefully inadequate in terms of demonstrating “a more refined approach” that assures the Commission that the use of EOP rate base “is not resulting in violation of the matching principle.” The Commission gave explicit direction to the parties concerning its expectation in this regard. Yet, Pacific Power and the other parties supporting its use of the EOP method in this case ignored this direction. Boise White Paper, on the other hand, offers both expert testimony and argument that goes to the heart of our concerns over the use of EOP rate base as the new standard.

151 We reject Pacific Power’s use of EOP rate base in this case, finding that the Company has failed to meet its burden of proof on this issue, and require that the Company’s compliance filing use the preferred AMA approach. We do not foreclose the possibility of approving EOP in a future case if there is an adequate showing that it promises the results we expect and is determined to be an appropriate regulatory mechanism under specific, well documented facts supporting its use.

²¹⁸ *Id.* ¶ 185.

²¹⁹ *Id.*

2. Major Capital Plant Additions (Adjustment 8.4)

- 152 Pacific Power proposed as part of its initial filing to include all post-test period capital projects with a budget greater than \$250,000 and planned to be placed in service between January 1, 2014, and March 31, 2015, the end of the suspension period in this case. The Company thus proposes in its initial filing the addition of 30 post-test-period projects as *pro forma* additions to rate base.²²⁰ This proposal contrasts sharply to what Pacific Power proposed in Docket UE-130043, in which the Company sought to include only four post-test period capital additions that were all over \$10 million on a Company-wide basis. Among the 30 projects included in Pacific Power's filing in this case, only one, the Merwin Project,²²¹ is indisputably a "major" plant addition.²²²
- 153 Mr. Mullins testifies for Boise White Paper that the Commission should reject the Company's proposal to include any *pro forma* capital additions in revenue requirement, with the exception of the Merwin Project. According to Mr. Mullins, removing these expenditures will result in a \$3.8 million reduction to the Company's revenue requirement.²²³
- 154 Fundamentally, Mr. Mullins' testimony is that the Company has failed to carry its burden to present the evidence necessary for the Commission to make an affirmative determination that each of the *pro forma* projects proposed by the Company satisfies the used and useful and known and measurable standards. He states that 25 of the proposed capital additions are supported by no more than "brief narrative descriptions included in an exhibit of Ms. Siores' testimony."²²⁴ According to Mr. Mullins, these descriptions "fall short of providing the Commission with the necessary information to determine whether these *pro forma* projects satisfy the heightened burden to be

²²⁰ Siores, Exh. No. NCS-1T at 26:8-13.

²²¹ The Commission rejected the Merwin Project as a capital plant addition in Docket UE-130043 because it was not shown to be used and useful during the time period of the case. Docket UE-130043, Order 05 ¶¶ 203-06.

²²² There is no directly applicable legal standard for what is a "major" project except in WAC 480-140-040, which establishes \$3 million in total project costs as the minimum size for a project to be considered "major".

²²³ Mullins, Exh. No. BGM-1CT at 2:18-22.

²²⁴ *Id.* at 11:2-3 (citing Siores, Exh. NCS-1T at 6:1-8; Exh. No. NCS-3 at 8.4.4-9.)

included in rate base.”²²⁵ He says these are relatively small projects with changing capital budgets and “highly uncertain” timing.²²⁶

155 Mr. Mullins cites as an example the Yale Upper Rock Block Stabilization project. He testifies it originally was planned to be placed in service in October 2014 at a total cost of \$2.7 million.²²⁷ Yet, Mr. Mullins states, according to the Company’s response to a Boise White Paper data request the planned in-service date changed to February 2015 and the total cost estimate increased to \$6.2 million.²²⁸ He says that “[m]any of the other small projects follow a similar pattern, which the Company has made no effort to explain in testimony.”²²⁹ For these reasons, he recommends that the Commission disallow the 25 projects supported only in Ms. Siores’ exhibit.

156 Turning to the remaining five projects Pacific Power proposes as *pro forma* major plant additions, Mr. Mullins opposes four: 1) the Jim Bridger Unit 1 Cooling Tower Replacement Project; 2) the Union Gap Substation Upgrade; 3) the Selah Substation Capacity Relief; and 4) the Fry Substation Project.²³⁰ The focus of his concern is what he characterizes as the uncertain costs and timing of these projects. Mr. Ralston testified as part of the Company’s initial filing that the Jim Bridger project would go

²²⁵ *Id.* at 11:6-8.

²²⁶ *Id.* at 11:8-11.

²²⁷ *Id.* (citing Exh. No. NCS-3 at 8.4.2).

²²⁸ Exh. No. BGM-4C (Pacific Power’s 1st Revised Response to Public Counsel (“PC”) DR 54, Attachment PC 54-1 1st Revised).

²²⁹ *Compare* Siores, Exh. No. NCS-3 at 8.4.2 and Siores Exh. No. NCS-11 at 8.4.2 (showing revisions to all proposed capital addition costs, including significant changes on some projects, and changed in-service dates for many projects). See also Public Counsel Initial Brief ¶ 52

[N]ot only did Pacific Power’s case materially change after the initial filing, but its rebuttal contained numerous errors and required further corrections, updates which were finalized only days before hearing. In general, the later in the case information is provided, the less opportunity there is to confirm it. Rather than allowing plant additions 10½ months after the end of the test year, Public Counsel believes a more reasonable compromise is to restrict additions to those before August 31, 2014, which helps ensure that the most reliable data is being used. Approving additions up to the time of rebuttal, and with even later revisions, reduces confidence in the reliability of the data.

²³⁰ *Id.* at 12:6-8.

into service in May 2014 at a cost of \$5.9 million.²³¹ During discovery, the Company provided updates showing an October 2014 in-service date and a cost of \$2.2 million.²³²

157 Public Counsel recommends that we allow as *pro forma* capital additions projects placed in service as of August 31, 2014, to the extent they are based on actual costs.²³³ In Public Counsel's view, this is an appropriate response to regulatory lag and rate case frequency. The bright-line cut-off date of August 31, 2014, is the latest date Public Counsel believes is appropriate in terms of allowing adequate time to review, particularly considering "concern about the significant number of changes and corrections to the Pacific Power plant additions in the later stages of the case."²³⁴ Coupled with the plant additions it supports, Public Counsel proposes a corresponding decrease to the Company's depreciation expense level for the test year to reflect plant, over \$250,000 on a Washington basis retired by June 30, 2014.²³⁵ Public Counsel contends its approach reflects the matching principle used in the test year to plant additions made after the test year.

158 Staff supports incorporating into rates plant that is in service at the time of rebuttal, provided the Company updates its *pro forma* additions with actual costs.²³⁶ According to Ms. Erdahl's testimony, "Staff's position reflects the Commission's statements in Order 05 from Docket UE-130043."²³⁷ She testifies further that "[i]n the Company's most recent rate case, the Commission accepted Pacific Power's end-of-period plant additions based on updated actuals as revised by the Company in its rebuttal testimony."²³⁸

²³¹ Ralston, Exh. No. DMR-1T at 4:4-9.

²³² Exh. No. BGM-4C (Pacific Power's Response to PC DR 54, Attachment 54-1).

²³³ See generally Ramas, Exh. No. DMR-1CT at 12:20-17:18. In direct testimony Ms. Ramas agrees to 11 *pro forma* major plant additions in service by June 30, 2014, if based on actual costs (Ramas, Exh. No. DMR-1T, at 13:25-14:2, 15:7-8, and 16:17-21.).

²³⁴ Public Counsel Initial Brief ¶ 51.

²³⁵ Ramas, Exh. No. DMR-1T, at 17:18- 18:3. The June 30 date is the same in-service cutoff date Public Counsel proposed for major plant additions in its initial testimony.

²³⁶ Erdahl, Exh. No. BAE-1T, at 8:4-8; 9:1-4.

²³⁷ *Id.* (citing Docket UE-130043, Order 05 ¶¶ 198-202).

²³⁸ *Id.* (citing Docket UE-130043, Order 05 ¶ 201).

159 Two business days before the hearing, the Company modified its *pro forma* adjustment approach to include only plant in service by the time of rebuttal and based on actual booked costs, essentially adopting Staff's position.²³⁹

160 In addition to the 25 capital additions for which Ms. Siores is the only Company witness, the Company's initial case included five proposed capital additions sponsored by other witnesses. These are:

- Merwin Fish Collector Project
- Fry Substation
- Selah Substation
- Union Gap Substation Upgrade
- Jim Bridger Unit 1 Cooling Tower Replacement Project

The Merwin Project is not contested. The Company removed the Fry and Selah Substation projects, which were not in service when it accepted Staff's recommendation for a cutoff date as of November 15, 2014. Boise White Paper recommends that the Commission reject for this rate case the remaining two projects, the Union Gap Substation Upgrade and the Jim Bridger Unit 1 Cooling Tower Replacement Project.

161 Mr. Mullins testifies that the Union Gap Substation Upgrade has been divided into three distinct phases, the first of which the Company describes as a preliminary step to make room for the final two phases to be completed in 2015. Boise White Paper argues that the first phase therefore is not used and useful when considered independently.²⁴⁰

162 Mr. Vail testifies for the Company, however, that "this project is prudent and necessary to continue to provide safe and reliable service to Washington customers

²³⁹ Dalley, Exh. No. RBD-10CX, TR. 386:18-390:2.

²⁴⁰ Mullins, Exh. No. BGM-1CTr at 14:1-8.

and to meet mandated NERC reliability standards.”²⁴¹ He says, in addition, that with construction for the first phase “complete and . . . placed in service in August 2014,”²⁴² “all of the associated equipment, including the distribution transformers, switchgear, and related assets, will be fully used and useful to serve the local area distribution load,” providing benefits “by increasing distribution capacity, replacing aged equipment, and mitigating protection system exposures.”²⁴³

163 Mr. Mullins also recommends that we reject the Jim Bridger Unit 1 Cooling Tower Replacement Project from the major plant additions adjustment. Boise White Paper argues that the costs associated with this project “have varied so significantly as to be irreconcilable with a reasonable application of the Commission’s demand for ‘a high degree of analytical rigor’ in order to satisfy the ‘known and measurable test.’”²⁴⁴ This argument, however, ignores Mr. Mullins’ related testimony explaining that the variability was due to errors by the Company in reporting in-service dates and costs for some projects.²⁴⁵ He acknowledges that the corrected information provided by Pacific Power “more closely aligned with the Company’s filing.”²⁴⁶

164 According to Pacific Power, the Jim Bridger Unit 1 Cooling Tower Replacement Project was completed and put in service “in May 2014, shortly after the Company filed its case.”²⁴⁷ According to the Company, “there is no uncertainty regarding the final costs of the project or the project’s in service date.”²⁴⁸

165 *Commission Determination:* The Commission’s long-standing practice is to consider post-test-year capital additions on a case-by-case basis following the used and useful and known and measurable standards while exercising the considerable discretion

²⁴¹ Vail, Exh. No. RAV-2T at 2:14-15.

²⁴² *Id.* at 5:13-15.

²⁴³ *Id.* at 2:23-3:4.

²⁴⁴ Boise White Paper Initial Brief ¶ 57 (citing Docket UE-130043, Order 05 ¶ 205 (quoting Docket Nos. UE-090704 and UG-090705 (consolidated), Order 11 ¶ 26)).

²⁴⁵ Mullins, Exh. No. BGM-1Tr at 13:1-9.

²⁴⁶ *Id.*

²⁴⁷ Pacific Power Initial Brief ¶ 126 (citing Ralston, Exh. No. DMR-1T at 4:7-9; Siores, Exh. No. NCS-10T at 18:19-19:3).

²⁴⁸ *Id.* (citing Siores, Exh. No. NCS-10T at 18:19-23).

these standards allow in the context of individual cases.²⁴⁹ This approach provides the Commission with flexibility when evaluating relevant factors without being confined by “too rigid an approach” through a consistent, bright-line standard.²⁵⁰

166 The Commission has made clear in prior orders that when the Company proposes a *pro forma* addition to rate base it has the burden of proof to show that resources allocated to Washington are “used and useful for service in this state.”²⁵¹ This means that the Company must demonstrate “quantifiable” benefits to ratepayers in Washington for each and every resource to be included in rates.²⁵²

167 As recently as the Company’s 2013 GRC, the Commission reiterated its definition of the known and measurable standard applicable to capital additions:

The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be known to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.²⁵³

168 We now turn to the bright line standards advocated by Public Counsel and Staff in this case (*i.e.*, respectively, August 31, 2014, and the date of Pacific Power’s rebuttal filing, November 15, 2014). In this regard, it is useful to recall the guidance the Commission provided in the Company’s prior GRC:

²⁴⁹ See Docket UE-130043, Order 05 ¶ 198.

²⁵⁰ *Id.* ¶¶ 198-99.

²⁵¹ See *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 ¶ 49 (April 17, 2006).

²⁵² *Id.* ¶ 51.

²⁵³ Docket UE-130043, Order 05 ¶ 205 (December 4, 2013) (quoting *WUTC v. PSE*, Dockets UE-090704 and UG-090705, Order 11 ¶ 26 (Apr. 2, 2010)).

Staff's idea that the Commission should have "a consistent and practical" "bright line" standard when evaluating what is "known and measurable" or "used and useful," though providing for some certainty in future application, is too rigid an approach. The Commission requires flexibility in most cases to exercise its informed judgment in ways that respond adequately and appropriately to the dynamic economic and financial circumstances that are characteristic of the utility industry and the general economy. Just as there are times when it is appropriate to depart from the preferred use of AMA rate base, as discussed above, there are times when it is appropriate to be more flexible in allowing post-test period *pro forma* adjustments and times when it is appropriate to be less flexible.

In sum, we reject the bright line cutoff dates proposed respectively by Staff and Public Counsel.²⁵⁴

While the Commission accepted three *pro forma* additions in 2013 based on updated actuals, as revised by the Company in rebuttal, it is clear from the discussion quoted above that the timing of the updates had nothing to do with the Commission's decision. Rather, the acceptance of these adjustments was based on the Commission's flexible exercise of discretion in applying its informed judgment to the record, and to its determination that it was appropriate "to be more flexible in allowing post-test period *pro forma* adjustments" in the specific context of the case before it.

169 Having just rejected the use of a bright-line cutoff date for the acceptance of post-test period additions to rate base and having just reiterated the Commission's standard for considering whether to allow such additions, we are confronted in this case with Staff and Public Counsel advocating bright-lines and the Company more or less ignoring the used and useful and known and measurable standards. The record in this case demonstrates why the Commission requires a more rigorous record and increasingly concrete support for *pro forma* adjustments the later in time plant additions are put in service and claimed to be used and useful. In this case the Company presents scant data concerning most of its proposed post-test period adjustments and the quality of its data has been shown to be poor and subject to revisions. Both cost and in-service date data presented in the original filing proved to be quite inaccurate for some

²⁵⁴ *Id.*, Order 05 ¶¶ 199-200.

projects. In addition, neither Staff nor Public Counsel present any evidence that they actually audited the data presented at any point in time. While Public Counsel's analyses during the case uncovered numerous errors in the data the Company presented the analysis was not an audit-level review. The Company's evidence and other parties' review falls far short of what we require to determine whether a proposed plant addition is used and useful and that its costs are known and measurable.

170 We also note that the relative size of many of the Company's proposed plant additions in this case falls short of any reasonable definition of "major" and there is no discussion in the record concerning possibly offsetting factors that may have occurred coincident with any of the plant going into service. In other words, neither the Company, nor any of the parties, appear to have taken into serious consideration the requirement to consider the matching principle for such capital additions.

171 Accordingly, we reject the *pro forma* plant additions to rate base for 25 of the 30 relatively small projects, described briefly in Ms. Siores revenue requirements exhibit as being insufficiently supported by the evidence.²⁵⁵ The brief descriptions of these 25 projects, supported by another two pages of data showing anticipated in-service dates and cost estimates, simply do nothing to establish that the projects should be added to rate base. The problems associated with not having accurate in-service dates or costs that can be considered known and measurable for these projects are illustrated by Mr. Mullins' example of the Yale Upper Rock Block Stabilization project, by his unrebutted testimony that similar problems plague the data displayed in Ms. Siores' revenue requirements exhibit, and by the fact that the Company found it appropriate to remove a number of projects immediately prior to our evidentiary hearing in this docket.²⁵⁶

172 Of the remaining five projects, the Company withdrew consideration of the Fry and Selah Substation projects, and the Merwin Project is not contested. Turning to the two remaining plant additions that are contested, the Union Gap Substation Upgrade and the Jim Bridger Unit 1 Cooling Tower, we find the Company satisfactorily demonstrated that both projects are used and useful and that their costs are known and measurable. Phase 1 of the Union Gap project met these criteria by August 2014, well in advance of the date for response testimony. The Jim Bridger project went on

²⁵⁵ See Exh. No. NCS-3 at 8.4.4 – 8.4.9.

²⁵⁶ See Exh. No. RBD-10CX; TR 386:18-390:2.

line even earlier, in May 2014. Accordingly, we accept the post-test year plant additions in rate base for the three projects mentioned above, including the uncontested Merwin Project.

3. Depreciation Study and Annual Depreciation (Adjustments 6.3 - 6.3.2 and 6.5)

- 173 Public Counsel proposes an adjustment to reflect the reduced depreciation expense associated with *pro forma* major plant retirements in determining revenue requirement.²⁵⁷ The Company agrees that this adjustment is appropriate for purposes of this case and developed Adjustment 6.5 (Retired Assets Depreciation Expense Removal) to reflect the removal of depreciation expense associated with major plant retirements exceeding \$250,000 on a Washington-allocated basis.²⁵⁸ According to Ms. Siores, “based on the most recent asset retirement information available,” including tax impacts, this adjustment decreases Washington revenue requirement by approximately \$29,000. The Company proposes to update this adjustment in its compliance filing to reflect the depreciation expense impact of actual major plant retirements before the rate effective date to maintain consistency with the Company’s proposed treatment of *pro forma* major plant additions.²⁵⁹
- 174 *Commission Determination:* This adjustment, to which Pacific Power and Public Counsel agree, appears to rest on the predicate that the Commission accepts the plant additions to which the Company and Staff agree. We do not, as discussed in the preceding section of this Order. We do not foreclose Pacific Power from recognizing this adjustment in its compliance filing, but we do not require it to do so.

G. “Fall-Out” Adjustments

- 175 We recognize two so-called fall-out adjustments, interest true up (Adjustment 7.1) and Production Factor (Adjustment 9.1). The amounts of these adjustments turn entirely on decisions concerning contested revenue requirements. The method for determining them is not disputed. It is the Commission’s practice, however, to include these in the table of contested adjustments included as an appendix to this Order. We will do so again in this case.

²⁵⁷ Ramas, Exhibit No. DMR-1CT at 17:19-19:8.

²⁵⁸ Siores, Exh. No. NCS-10T at 11:16-12:3.

²⁵⁹ *Id.* at 12:4-7.

H. Capital Structure and Cost of Capital

- 176 Pacific Power and other parties presented in the Company's 2012/2013 GRC, Docket UE-130043, the full panoply of evidence typically filed in cases where the Company's capital structure, cost of equity, and overall weighted cost of capital (*i.e.*, overall rate of return, or ROR) are contested. The Commission determined the issues on their merits, as discussed in detail in the Commission's Final Order in the case.²⁶⁰
- 177 Pacific Power filed a petition for judicial review of Order 05, as discussed above in connection with the issue of the allocation of QF power costs. In its petition, the Company also challenges the Commission's determination of cost of capital, focusing specifically on the Commission's rejection of Pacific Power's argument that the Commission must rely on the capital structure of PacifiCorp, the Company's corporate parent, as a surrogate for Pacific Power's "actual capital structure" when, in fact, Pacific Power has no capital structure of its own.²⁶¹
- 178 Yet, in the present case, filed just five months after the Commission entered its final order in Docket UE-130043, Pacific Power has put forward a full cost of capital case. Staff, Public Counsel, and Boise White Paper, in response, each put on full cost of capital cases and all parties fully briefed the issues. The only difference between the capital structure proposed in this case and the previous one, now subject to judicial review, is a slight change in the level of equity proposed (*i.e.*, 51.73 percent) because "the Company used an average of PacifiCorp's five-quarter ends spanning the

²⁶⁰ Docket UE-130043, Order 05 ¶¶ 22-73. The Commission devoted 21 pages to the analysis and discussion of cost of capital issues, more than 20 percent of the 97 pages of substantive discussion included in Order 05.

²⁶¹ TR. 178:2-7 (cross-examination of Mr. Williams by Public Counsel). We note Mr. Williams' testimony that "it's not an apt comparison to compare the holding company [Berkshire Hathaway Energy or BHE] to PacifiCorp" because "much of the financing that Berkshire Hathaway, the ultimate parent company, has provided to BHE is in the form of debt that's structured to receive equity credit from the rating agencies." The Commission will explore in the Company's next case whether it is also true that some part of the capital that BHE has provided to PacifiCorp is actually debt yet reflected in PacifiCorp's capital structure as equity.

12 months ending December 31, 2014,”²⁶² instead of “the five-quarter end spanning the 12 months ending June 30, 2013”²⁶³ used in Docket UE-130043.

- 179 In Docket UE-130043, Pacific Power argued that its weighted cost of capital should be based on a 10.0 percent rate of return on equity (ROE), its actual long-term debt costs and its actual costs of preferred stock.²⁶⁴ The Company argued that its capital structure should not include short-term debt. The Commission, based on a detailed analysis of the full record, determined that “[t]he Company failed to carry its burden in this case to support its proposed 10.0 percent return on equity,” and authorized a 9.5 percent ROE.²⁶⁵ The Commission authorized a 49.1 percent equity layer based on a hypothetical capital structure for the Washington-jurisdictional rate base. Also, in that case, the Commission agreed with the Company’s actual costs for long-term debt and preferred stock, and did not impute short-term debt into the capital structure.
- 180 In this case, Pacific Power argues again that its weighted cost of capital should be based on a 10.0 percent ROE, its actual long-term debt costs and its actual costs of preferred stock. The Company “continues to believe that it is inappropriate and inequitable to include short-term debt in the capital structure for Pacific Power,” but “included projected quarter-end short-term debt balances for the period ending December 31, 2014.”²⁶⁶ The imputation of short-term debt, like the use of actual preferred stock data, however, has no practical impact on the weighted cost of capital (*i.e.*, overall rate of return) determined for setting rates, which we round to two decimal places.²⁶⁷
- 181 The level of equity in Pacific Power’s capital structure (*i.e.*, the “equity ratio”) and the ROE are the only contested issues on the subject of cost of capital in this docket. The Commission resolved these issues on a full record in Docket UE-130043 in December 2013, just months before the Company filed this general rate case in May 2014. Although the parties presented evidence on these issues, we determine that this

²⁶² Williams, Exh. No. BNW-1T at 4:17-18.

²⁶³ Docket UE-130043, Order 05 ¶ 35 (quoting Williams, Exh. No. BNW-1T at 12:12-19).

²⁶⁴ *Id.* ¶ 43.

²⁶⁵ *Id.* ¶¶ 63, 70.

²⁶⁶ Williams, Exh. No. BNW-1T at 5:9-22.

²⁶⁷ *See Id.* at 23, Table 8.

evidence does not demonstrate any significant change in capital markets, or in the Company's ability to access such markets, that would justify rehearing them in this case. We therefore exercise our discretion under RCW 80.04.200 not to rehear these so recently resolved issues in this proceeding.²⁶⁸

182 We refrain from rehearing these issues, in addition, because we should not risk disrupting the Court of Appeal's orderly consideration of Pacific Power's appeal of Order 05 in Docket UE-130043 on the issue of capital structure. The equity ratio in the Company's capital structure and its allowed ROE are inextricably intertwined issues as components that go into determining the Company's overall rate of return that is used in determining revenue requirements.²⁶⁹ Given that it is the overall return that defines the "end result" that is the rate regulatory goal, we should await any direction the Court of Appeals may give on capital structure before revisiting the related issue of cost of equity.²⁷⁰ The Company's return on equity will remain at 9.5 percent for purposes of this case.

183 With respect to the remaining components of the Company's capital structure and costs, the issues are uncontested. We adjust the Company's long-term debt ratio to reflect our decision not to revisit the equity ratio and in light of our acceptance of the Company's as-filed ratios and costs for short-term debt and preferred stock. Thus, the Company's capital structure and cost of capital for purposes of setting rates in this proceeding are as illustrated in Table 2.

²⁶⁸ *US West Communications, Inc. v WUTC*, 134 Wn.2d 74 (1997); *see supra* ¶ 75, n. 98.

²⁶⁹ Goodman, in his treatise, observes that "[t]he adopted capital structure is the 'glue' that holds together the overall cost of capital and resulting rate of return." Leonard Saul Goodman, The Process of Ratemaking, 648 (1998). We disagree with Mr. Williams' testimony that rejection of the Company's parent corporation's capital structure means the Commission should put a hypothetical cost of debt into that structure in lieu of the Company's actual costs of debt. His testimony, however, illustrates the point that different equity ratios included in the capital structure *may* affect the Commission's determination of the cost of equity, which is arrived at indirectly, in contrast to debt costs that are observed directly. *See Williams, Exh. No. BNW-1T at 10:14-17*: "While the Company's primary recommendation is based on its actual capital structure, the Company is also proposing an alternative hypothetical capital structure that includes a reduced equity component, but also reflects the impact of that change on the costs of debt and equity."

²⁷⁰ *See Fed. Power Comm 'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 602-03 (1944).

TABLE 2			
Capital Structure and Cost of Capital			
	Share	Cost	Weighted Cost
Equity	49.10%	9.50%	4.67%
Long-Term Debt	50.69%	5.19%	2.63%
Short-Term Debt	00.19%	1.73	0.00%
Preferred Stock	00.02%	6.75%	0.00%
OVERALL Rate of Return			7.30%

I. Summary of Revenue Requirement Determinations

184 Appendix A to this Order shows the Commission’s determinations of the contested adjustments discussed above. Appendix B shows the uncontested adjustments, which we approve without the need for further discussion. Based in part on these adjustments, we portray in Table 3 the revenue requirement that we approve for recovery in rates.

TABLE 3	
Revenue Requirement	
Rate Base	\$818,890,931
Rate of Return	7.30%
Net Operating Income (NOI) Requirement	\$59,779,038
<i>Pro Forma</i> NOI	53,850,896
Operating Income Deficiency	\$5,928,142
Conversion Factor	0.61955
Gross Revenue Requirement Increase	\$9,568,464

J. Rates to Customers

1. Cost of Service Study

a) *Classification of Generation and Transmission Costs*

185 Pacific Power proposed in its cost of service study (COSS) in Docket UE-130043 to use what is generally known as the Peak & Average (P&A) method to classify generation and transmission plant as “demand-related” or “energy-related.”²⁷¹ This replaced the Peak Credit methodology previously approved for the Company. Mr. Watkins, testifying for Public Counsel, discusses that:

The P&A and Peak Credit methods are distinctly different both conceptually as well as mathematically. The P&A and Peak Credit methods both recognize energy usage and peak load (demand). However, the Peak Credit method, also known as the Equivalent Peaker method in other jurisdictions, combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal costs studies, whereas the P&A method is strictly an embedded (historical) cost allocation approach.²⁷²

186 The Commission approved use of the P&A method as part of a partial settlement in the 2013 case with the expectation that the issue would be revisited here.²⁷³ Company witness Ms. Steward uses the same calculation in this case as used in the Company’s 2013 Rate Case employing the WCA system diversified load factor (SDLF) to determine the proportion of generation and transmission costs that are demand related. This results in 43 percent of generation and transmission costs classified as demand related and the remaining 57 percent of costs classified as energy related.

²⁷¹ We note that in Pacific Power’s 2013 general rate case, the Company referred to this methodology as a “Revised Peak Credit” method. The P&A method was adopted as part of a partial settlement in that proceeding.²⁷¹

²⁷² Watkins, Exh. No. GAW-1T at 9:1-7.

²⁷³ Docket UE-130043, Order 05 ¶ 251; *see generally* *Id.* ¶¶ 242-251.

187 Public Counsel does not oppose the use of the P&A method but disagrees with the number of coincidental peak (CP) hours the Company uses in its P&A method. Public Counsel is concerned about the “reasonableness and stability” of the Company’s reliance on the single highest hour of system peak (1-CP) to classify costs to demand.²⁷⁴ Public Counsel recommends using instead the Company’s 2013 IRP Update, or in the alternative 4-CP, 6-CP, or 8-CP.²⁷⁵ Table 4 shows the results of these alternative methodologies.

Table 4

Party Proposing & Method of Calculation	Year	Demand	Energy
Company’s 1-CP	2014 GRC	43%	57%
Public Counsel’s IRP Update	2014 GRC	28%	72%
Peak Credit	2014 GRC	35%	65%
Company’s 1-CP	2013 GRC	38%	62%

188 Ms. Steward testifies that use of the IRP data is not appropriate because the IRP “looks at the loads of the west control area at the time of the Company’s entire system peak, while the Company’s studies look at only WCA peak.”²⁷⁶ Thus, the difference in the IRP coincident peaks and the peak used by the Company are explained simply by the fact that the Company-wide peak and the WCA peak occur at different times.²⁷⁷ Using Public Counsel’s preferred approach would shift costs from lower load-factor customers (*i.e.*, residential customers) to higher load factor customers (*i.e.*, industrial and large general service customers).²⁷⁸

189 Boise White Paper does not support the Company’s use of any type of peak credit method to classify generation costs. Instead, it proposes that the Company classify all fixed generation costs as demand-related, and all of the variable generation costs as energy-related.²⁷⁹ Boise White Paper witness Mr. Stephens testifies, however, that if the Commission approves a peak credit method, it should use a 2-CP, 3-CP, or 4-CP

²⁷⁴ Watkins, Exh. No. GAW-1T at 11:10-15.

²⁷⁵ *Id.* at 12:12-18.

²⁷⁶ Steward, Exh. No. JRS-13T, 6:15-22.

²⁷⁷ *Id.*

²⁷⁸ *Id.* at 7:1-9.

²⁷⁹ Stephens, Exh. No. RRS-1T at 17:1-18:2.

factor for demand related production costs.²⁸⁰ Mr. Stephens testifies further that there is no justification for using an energy component in allocating transmission costs.

190 *Commission Determination:* The Commission has long preferred the Peak Credit methodology and consistently has approved its use in cost of service studies for Pacific Power, and for both PSE and Avista. Mr. Watkins for Public Counsel and Mr. Stephens for Boise White Paper explore this topic in some detail. Mr. Watkins does not oppose the P&A methodology the Company uses here, as it did in its 2013 GRC, but recommends several alternative adjustments in its application. Mr. Stephens opposes the P&A and the Peak Credit methodologies and suggests additional alternatives. Mr. Watkins, moreover, discusses that there are numerous methodologies that suggests different classification and allocation approaches related to demand.²⁸¹

191 We are not persuaded by the record in this case that we should reject Pacific Power's approach to classification of generation or transmission costs. Hence, we accept the continued use in this case of the P&A method approved and adopted as part of a settlement in the previous GRC. However, the parties raise sufficient concerns to persuade us that the Company should return in its next case to using the Commission-approved Peak Credit method or provide a more detailed justification for using an alternative approach, or approaches including the use of Peak and Average method compared to the Peak Credit method, as well as consideration of the number of hours that should be used within these methods.

b) Allocation of Demand Classified Generation and Transmission Costs to Customer Classes

192 After classifying costs, the next step in a COSS is to allocate costs. The Company's allocation of demand-classified generation and transmission costs to customer classes

²⁸⁰ *Id.* at 19:5-8.

²⁸¹ According to Mr. Watkins:

The current National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual* discusses at least 13 embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise *Principles of Public Utilities Rates*.

Watkins, Exh. No. GAW-1T at 6:13-18.

is based on the top 100 hours in summer and top 100 hours in winter, sometimes called the 200 Coincident Peak (CP) methodology.

193 Boise White Paper argues against this approach and in favor of a method that considers only the hourly demands that are reasonably close to the system peak. Mr. Stephens testifies in this regard that:

By considering only the hourly demands that are reasonably close to the annual system peak, the cost analyst recognizes that it is only during the highest system load hours that production capacity is most likely to be fully utilized. Consequently, a demand allocation method that is based on each class's contribution during these high demand periods will fairly and reasonably recognize the classes' proportionate responsibility in causing the utility to incur those production investments.²⁸²

Boise White Paper proposes using the highest two monthly load hours in summer and winter months (*i.e.*, a 4-CP method).²⁸³ Public Counsel argues that Boise White Paper's proposal ignores the trade-offs that utilities make when deciding to build base load plants or peaker plants; because this trade-off exists, generation must be classified as partially demand and partially energy-related.²⁸⁴ Public Counsel also notes that Boise White Paper's proposal represents a departure from Commission precedent dating back to 1981.²⁸⁵ Similarly, the Company cites to Pacific Power's 2010 GRC in which ICNU proposed to use the same 4-CP method. The Commission rejected that proposal, saying:

As we have in the past when presented with a precise revision to peak demand, we conclude that this is too narrow a range. We agree with PacifiCorp that ICNU's proposal could produce volatility in results depending on the test period. While it is reasonable to allocate the costs of peaking resources based on the hours those resources will actually be used to serve load, the allocation method should be flexible

²⁸² Stephens, Exh. No. RRS-1T at 9:7-14.

²⁸³ *Id.* at 11-12.

²⁸⁴ Watkins, Exh. No. GAW-6T at 13:7-14:3.

²⁸⁵ *Id.* at 2 (note 1).

enough to incorporate the variable peaks experienced in Washington. PacifiCorp experiences both a summer peak and a winter peak, and its proposal to include 100 summer hours and 100 winter hours to determine peak demand recognizes how resources are used.²⁸⁶

194 *Commission Determination:* The Commission has found it appropriate for some time to use the 200 CP method to allocate Pacific Power's generation and transmission costs considering how the Company's resources are used to serve customers in Washington. We find insufficient basis in the current record to depart from this approach.

c) Corporate Account Manager Expenses

195 Staff and Public Counsel recommend the direct assignment of costs associated with corporate account managers for industrial customers that take service under Pacific Power's Tariff Schedule 48T.²⁸⁷ Pacific Power does not oppose this change, but does not include the proposal in its COSS because of the minimal impact.²⁸⁸ Boise White Paper does not support this proposal, asserting that, as a matter of fairness, Schedule 48T customers are assigned costs related to residential customer service (*i.e.*, call centers) from which they receive no benefit.²⁸⁹

196 *Commission Determination:* While there is merit to the idea of directly assigning costs that are easily identified to specific customer, Boise White Paper's fairness argument also has merit. Thus, were we to make the change Staff and Public Counsel recommend, we would also need a record to show what specific customer service costs might be demonstrably inappropriate to allocate to industrial customers. Without such a record, we find it appropriate to retain the status quo and reject Staff and Public Counsel's recommendation.

²⁸⁶ *WUTC v. PacifiCorp*, Docket UE-100749, Order No. 06 ¶¶ 104-105 (Mar. 25, 2011).

²⁸⁷ Watkins, Exh. No. GAW-1T at 15:8-20.

²⁸⁸ Steward, Exh. No. JRS-1T at 12:9-13:1.

²⁸⁹ Stephens, Exh. No. RRS-9T at 5:13-6:12.

2. Rate Spread

197 A utility performs a COSS to determine its cost to serve each class of customers. The primary result of the study is a parity ratio, calculated by dividing the revenue collected from each customer class by the cost to serve that customer class.²⁹⁰ As a general matter, it is appropriate from case to case to move the rates of each customer class closer to parity. Changes in rates to effect greater parity, however, must take into account “fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.”²⁹¹

198 *Pacific Power* presents its rate spread proposal through Ms. Steward’s testimony.²⁹² She explains that the Company, relying on its COSS, proposes to: (1) allocate an increase based on one-half of the overall 8.5 percent proposed increase in revenue (*i.e.*, 4.2 percent) to rate Schedules 24 (Small General Service), 40 (Agricultural Pumping), and lighting schedules because the cost of service study indicates parity ratios for these customers that show they are paying more than the cost of serving them. The Company proposes that the remaining increase should be spread equally to the remaining rate schedules, which results in a 9.5 percent increase for those schedules.

199 Public Counsel accepts the Pacific Power rate spread recommendation for base rate revenue allocation (rate spread).²⁹³ According to Public Counsel:

The Company proposal reflects movement towards allocated costs under Ms. Steward’s COSS. It also reflects the principle of gradualism

²⁹⁰ A parity ratio is one measure of whether a customer class is paying the approximate amount needed to cover its share of costs. A parity value of one means that a customer class is paying the approximate amount to cover its share of costs.

²⁹¹ *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08, ¶ 350 (May 7, 2012).

²⁹² Steward, Exh. No. JRS-1T at 13:8-15:9; Exh. No. JRS-13T at 17:1-19:14.

²⁹³ Public Counsel Initial Brief ¶ 102 (noting that at the Company’s original revenue requirement of \$27.2 million, this would result in the Residential class receiving an increase of 9.5 percent and the Small General class receiving 4.2 percent. At the Company’s final revenue requirement number of \$31.9 million, the Residential class increase would be 11.2 percent, and 13 percent if deferral requests are included. Steward, Exh. No. JRS-16 at 3).

in that the Residential class will sustain a somewhat larger increase than the overall system average (8.5% under the original request) and the Small General Service a smaller increase. The percentage increase would be scaled back proportionately if, as requested by Public Counsel and other parties, the overall increase is less than the amount requested by the Company.²⁹⁴

200 As illustrated in Table 5 below, alternative proposals by Boise White Paper and Walmart are in most respects quite similar to the Company’s proposal.

Table 5
Rate Spread Proposals

Schedule	Company’s Proposal	Boise’s Proposal	Wal-Mart’s Proposal	Staff’s Proposal
16, Residential	112%	112%	112%	150%
24, Small General Service	50%	45%	68%	0%
36, Large General Service <1 MW	112%	112%	100%	70%
48T, Large General Service >1 MW	112%	112%	100%	100%
48T, Dedicated Facilities	112%	112%	112%	150%
40, Agricultural Pumping	50%	71%	68%	0%
Street Lighting	50%	55%	50%	0%

201 Staff is the outlier, recommending, among other things, that the Residential class contribute 150 percent of the system average percentage increase, while small general service customers bear none of the increase. Staff’s proposal is to bring each schedule’s rates within 5 percent of parity in a single move.

202 *Commission Determination:* Staff’s proposal would certainly move the rate spread toward greater parity in a single move. However, it fails to take into account the other factors the Commission has identified as necessary considerations when making

²⁹⁴ *Id.*

changes in rate spread: fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability. Indeed, in Pacific Power's 2010 GRC the Commission found that increases of 114 percent of the average were too extreme.²⁹⁵ The other parties' proposals effectively present a more measured move in the direction of greater parity, capping the disproportionate increases to residential and other customer classes at 112 percent of the average increase. On balance, while we appreciate Staff's efforts to move quickly toward greater parity, we believe the Company's proposal comports best with principles the Commission has enunciated in prior orders. We therefore accept the Company's proposal in this case.

3. Rate Design

a) Residential Rates

203 Pacific Power proposes to increase the residential basic charge for Schedule 16 customers from \$7.75 per month to \$14.00 per month, an 81 percent increase from the current level. The Company would make an exception for Schedule 17, which sets rates for qualifying customers under the Company's Low Income Bill Assistance (LIBA) Program, increasing the basic charge by one dollar to \$8.75. Ms. Steward testifies that the Company's embedded cost of service results supports an even higher basic charge of \$28.00 per month.²⁹⁶ This figure includes distribution system fixed costs (line transformers, poles, and wires), now recovered in volumetric rates, as well as the traditional costs included in basic charges that vary based on the number of customers served (service drops, meters, meter reading, and billing).²⁹⁷ Ms. Steward implies that all fixed costs are appropriate for inclusion in the basic charge, including transmission and generation, which would raise the charge even more, to \$47.00 per month.²⁹⁸

204 Staff proposes increasing the basic charge to \$13 to allow the company more stable revenues and in support of its proposal to add a third volumetric block to encourage conservation and distributed generation (DG).²⁹⁹ Staff reaches its proposed \$13 basic

²⁹⁵ *WUTC v. PacifiCorp*, Docket UE-100749, Order 06, ¶ 315 (March 25, 2011).

²⁹⁶ Steward, Exh. No. JRS-1T at 19:1-18.

²⁹⁷ *Id.* at 19:1-18.

²⁹⁸ *Id.* at 19:7-9.

²⁹⁹ Twitchell, Exh. No. JBT-1T at 4:10-19.

charge by including the cost of line transformers, a distribution system cost previously included in energy rates.³⁰⁰

- 205 Public Counsel, TASC, and the Energy Project all offer testimony that the basic charge should include only costs that vary based on the number of customers served.³⁰¹ Public Counsel and TASC argue, based on the traditional “direct customer cost” analysis and a Regulatory Assistance Project paper, that transformer costs vary based upon demand and should be included in energy rates.³⁰² Public Counsel and TASC also argue that the Company’s increase in the basic charge violates the regulatory principle of gradualism and is contrary to conservation efforts.³⁰³ Mr. Watkins, for Public Counsel calculates that using traditional “direct customer cost” analysis, the basic charge should be between \$7.31-7.50.³⁰⁴ Mr. Fulmer, for TASC, supports a basic charge of \$9.00.³⁰⁵ Mr. Eberdt testifies that the Energy Project opposes an increase to the basic charge for all customers.³⁰⁶
- 206 *Staff* supports its proposed increase in the basic charge by reasoning that “in the absence of a decoupling mechanism to reduce Pacific Power’s risk of under-recovering fixed costs due to declining load, it is appropriate to shift the distribution of the Company’s cost recovery toward fixed sources of recovery, such as the monthly basic charge.”³⁰⁷ Mr. Fulmer, for TASC, points out that increasing the basic charge would discourage distributed generation, and that decoupling, attrition adjustments, minimum bills and forward-looking test years are more appropriate ways to address utility revenue deficiency than higher fixed charges.³⁰⁸ *Staff* agrees with

³⁰⁰ *Id.* at 26:21-27:7.

³⁰¹ Watkins, Exh. No. GAW-1T at 27:1-30:22; Fulmer, Exh. No. MEF-1T at 6:1-8:2; Eberdt, Exh. No. CME-13 at 10.

³⁰² Fulmer, Exh. No. MEF-1T at 9:17-21 (note 9) (*citing* Weston, Frederick, “Charging For Distribution Utility Services: Issues In Rate Design,” the Regulatory Assistance Project. (December 2000)).

³⁰³ Watkins, Exh. No. GAW-1T at 17:17-21; Fulmer Exh. No. MEF-1T at 10:3-12:16.

³⁰⁴ Watkins, Exh. No. GAW-1T at 27:15-20.

³⁰⁵ Fulmer, Exh. No. MEF-1T at 3:3-4.

³⁰⁶ Eberdt, Exh. No. CME-1T at 21:17-22:16.

³⁰⁷ Twitchell, Exh. No. JBT-1T at 26:15-18. Pacific Power provides a similar argument in support of revenue stability. *See* Steward Exh. No. JRS-1T at 19:19-21:17.

³⁰⁸ Fulmer, Exh. No. MEF-1T at 12:20-28.

TASC on this point, stating in its Initial Brief that it is curious that Pacific Power did not request a decoupling mechanism in this case. Staff argues that “[t]he decoupling mechanisms recently approved by the Commission provide the affected utilities a guaranteed amount of revenue, regardless of actual retail sales.”³⁰⁹ In Staff’s view, a decoupling mechanism would provide the Company more certainty of cost recovery than do other approaches.

207 Staff combines an increase in the basic charge with the addition of a third volumetric block to Pacific Power’s residential rates in order to:

- Provide the Company more reliable recovery of fixed costs.
- Establish clear price signals for consumers that support energy efficiency and distributed generation.

208 *The* bases for Staff’s three-block proposal are:

- Block 1 to correspond to inelastic use,
- Block 2 to reflect average use, and
- Block 3 to assign a greater share of the increase to high-use customers and not impose additional costs on average users.³¹⁰

Staff proposes this new structure to send a price signal that encourages conservation among customers with discretionary, or elastic, electricity use. Staff attempts to set the first volumetric block to cover a typical customer’s inelastic consumption, thereby placing discretionary use in the second and third volumetric blocks.³¹¹

209 Relying on a U.S. Dept. of Housing and Urban Development (HUD) guidebook, Staff believes that the first 800 kWh of residential usage is inelastic because it represents use for essential needs (e.g., cooking, domestic hot water, lighting, and home

³⁰⁹ Staff Initial Brief ¶ 117 (citing Twitchell, Exh. No. JBT-1T at 24:5-11; *see* Dockets UE-140188 and UG-140189, Order 05).

³¹⁰ Twitchell, Exh. No. JBT-1T, at 12:28-29.

³¹¹ *Id.* at 28:1-13.

appliances).³¹² Using data from its 2013 IRP the Company argues that the amount of electric energy use for the most common types of appliance and lighting load in a home is under 600 kWh per month.³¹³ This 600 kWh excludes electric heating, which is present in 56 percent of homes in the Company's service territory.³¹⁴

210 Staff witness Mr. Twitchell estimates that the addition of the third block could result in as much as 7,660 MWh of savings annually, or 14 percent of the company's average annual conservation savings.³¹⁵ The Company claims that its rate design will result in 2 percent more conservation because a higher volumetric rate (from sales in the larger second block) would apply to more kWh sales.³¹⁶

211 Under Staff's proposal, most customers with average use will see a bill decrease, while low use and high use customers will see a bill increase. The Company argues that lower bills for most customers mean that Staff's proposal does not encourage conservation.

212 The Company does not believe that Staff's rate design will improve its revenue stability because it will recover 22 percent of its revenue from the third block, in contrast to its own rate design, which will recover 18 percent of revenues from use over 1,700 kWh.³¹⁷ The Company argues that as a result of Staff's proposal, variances in weather will result in larger variances in revenues.³¹⁸

213 Mr. Eberdt testifies that "the Energy Project opposes any increase to the monthly residential basic charge until such time as more thorough data is available and analyzed regarding the true number and nature of PacifiCorp's low income customers and their energy consumption."³¹⁹ Some low-income customers are relatively high

³¹² *Id.*

³¹³ Steward, Exh. No. JRS-13T at 44:15-20.

³¹⁴ *Id.* at 45 (Table 14).

³¹⁵ Twitchell, Exh. No. JBT-1T at 33:8-11. The estimate was developed using state-specific price elasticity data from a 2006 National Renewable Energy Lab study. *Id.*

³¹⁶ Steward, Exh. No. JRS-21; Steward Exh. No. JRS-13T at 39:9-12.

³¹⁷ Steward, Exh. No. JRS-13T at 39:23-40:2.

³¹⁸ *Id.* at 40:3-17.

³¹⁹ Eberdt, Exh. No. CME-1T at 24:2-5.

users in the winter months, not by choice, but because of poor housing stock and an inability to finance conservation measures such as insulation and more efficient heating. To these customers, an increased basic charge coupled with a third tier rate will mean increases in monthly bills to customers who can least afford it.³²⁰ At the other end of the low-income spectrum, very low volume users will experience significantly higher bills and a disproportionate impact from an increased basic charge. Because of these impacts, the Energy Project supports raising the upper end of the first block from 600 to 800 kWh, but thinks the beginning of the third block should be higher than 1,700 kWh. Mr. Eberdt argues that many low-income customers would be subject to third block rates in the winter, “running the risk of greater shut-offs and less revenue recovery than expected.”³²¹ Mr. Eberdt provides data that shows in two months, January and December 2013, average low-income use was about 2,200 kWh and would result in higher bills under Staff’s proposal; in all other months average low-income use was in the range that will result in bill reductions.³²²

214 *The Energy Project argues that the Company's proposal to increase the basic charge by only \$1.00 for low income customers who receive benefits under either LIHEAP or LIBA does not recognize the scope of the problem increased basic charges pose for the low-income population.³²³ The Energy Project points to Staff witness Mr. Kouchi’s testimony that the LIHEAP/LIBA recipients to whom Schedule 17 applies constitute only 5.6 percent of the Company's residential population, yet the poverty levels in Pacific Power’s Yakima and Walla Walla service areas might be as high as 23 percent to 38 percent respectively.³²⁴ “Thus, limiting the basic charge increase to only those customers already receiving some form of assistance hardly scratches the*

³²⁰ Energy Project Initial Brief at 7.

³²¹ Eberdt, Exh. No. CME-8T at 3:14-17. This is because low-income households rely on electric resistance for space and hot water heating more than other customers. *Id.*, 4:1-13.

³²² Eberdt, Exh. No. CME-13.

³²³ *See* Eberdt, Exh. No. CME-1T at 22:4-13.

³²⁴ Energy Project Initial Brief at 3; *See* Kouchi, Exh. No. RK-1T at 9:1-4. These figures refer only to customers who are at 150 percent or less of the federal poverty threshold, the qualifying criterion for the Company’s low-income programs. The percentages of low-income customers at 200 percent of the federal poverty level, a threshold used by some utility companies, range even higher from 31 to 49 percent. *Id.* at 9:10-15.

surface of the true low income population, the majority of whom will bear the full brunt of a considerable basic charge increase.”³²⁵

215 Mr. Eberdt also testifies that “we just don’t have a good handle on the usage characteristics of PacifiCorp’s low-income customers,” due to conflicting usage data from the Company’s proxy group (LIBA and LIHEAP participants) and the Company’s residential use survey completed last year.³²⁶ Accordingly, he recommends rejecting Staff’s proposal and requiring the Company to conduct another study that better identifies low-income customers and their usage characteristics.³²⁷ Mr. Eberdt acknowledges that this recommendation is the same as the outcome in the Company’s previous general rate case, but argues that the usage study was not done well enough.

216 *Commission Determination:* We reject the Company’s and Staff’s proposals to increase significantly the basic charge to residential customers. The Commission is not prepared to move away from the long-accepted principle that basic charges should reflect only “direct customer costs” such as meter reading and billing. Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals.

217 Staff’s similar proposal to raise the basic charge significantly from the current level is tied to its other major rate design recommendation, which is to move Pacific Power’s residential rates from a two-block to a three-block inverted rate structure. Such rate restructuring might promote conservation to a degree that offsets the incentive to use more electricity that may be caused by a high basic charge but we are not convinced on the record in this case that this is so. Mr. Twitchell, for Staff, performed some analysis of this question as reflected in his testimony in some detail.³²⁸ He cautions, however, that his results “are only rough projections.” He testifies that “there are a number of other factors that will affect the total reduction in electricity usage. Staff’s

³²⁵ Energy Project Initial Brief at 3.

³²⁶ Eberdt, Exh. No. CME-9T at 13:12-14:5.

³²⁷ *Id.* at 14:7-15:3.

³²⁸ Twitchell, Exh. No. JBT-1T at 30:12-33:11.

projection should be interpreted as an upper-bound estimate of the reduced usage that may occur.”³²⁹

- 218 The Commission supports generally the concept of adding a third block to residential rates because it sends a price signal that promotes conservation and distributed generation. Yet we hesitate to implement a third block with a low basic charge in this case because, as Staff acknowledges, “Staff’s core proposals (the increased basic charge and the third rate block) are mutually dependent.”³³⁰ No party provides analysis of the customer bill impact and company revenue impact of implementing a third block with a low basic charge. Without this analysis in the record, we are unwilling to implement a third block with a low basic charge in this case.
- 219 While we hope to see in the Company’s next case a proposal from Pacific Power, Staff, or other parties for a third block rate that is not tied to a higher basic charge for residential customers,³³¹ we remain concerned about the impact of adding a third block on low-income customers. We acknowledge and commend the parties for presenting data and some analysis of the issue in the record of this case. However, the evidence does not dispel the concerns raised by the Energy Project that the rate design proposals by the Company and Staff will disproportionately impact the customers least able to afford high basic charges and high third-block usage rates. We expect the Company and others to continue developing data and undertaking analyses of low-income customer usage patterns in Pacific Power’s service territory. These can inform thoughtful consideration in testimony in the Company’s next general rate case concerning the price signals a third block rate design will likely have on such customers.
- 220 Several parties touch on decoupling, recognizing it as the Commission’s preferred approach to address the various goals the Company and Staff residential rate design proposals are meant to address. The Commission’s long history with decoupling dates back to 1991, when the Commission first approved decoupling for PSE’s

³²⁹ *Id.* at 33:12-15.

³³⁰ Staff Initial Brief ¶ 130.

³³¹ We note the Commission’s approval of such a rate design for Avista and the Commission’s recent approval of a settlement adding a third block to PSE’s residential rates. See *WUTC v. Avista Corp.*, Docket UE-140188 and UG-140189, Order 05 (November 25, 2014); *WUTC v. Puget Sound Energy, Inc.*, Docket UE-141368, Order 03 (January 29, 2015).

predecessor electric company, Puget Sound Power & Light Company.³³² In 2005, the Commission conducted a rulemaking inquiry into the subject of decoupling. After taking stakeholder comments and conducting a workshop, the Commission determined that “the wide variety of alternative approaches to decoupling make it more efficient to address these issues in the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking.”³³³

221 Following this, the Commission considered several decoupling proposals, implementing some and rejecting others.³³⁴ In its 2010 Decoupling Policy Statement, the Commission expressed support for full decoupling and provided utilities and other parties with guidance on the elements that a full decoupling proposal should include.³³⁵ Essential to the policy was recognition that the mechanism should aid the company when revenue per customer decreases and aid the customer when revenue per customer increases. The Commission stated that it believed that “a properly constructed full decoupling mechanism that is intended, between general rate cases, to balance out both lost and found margin from any source can be a tool that benefits

³³² *WUTC v. Puget Sound Power & Light Company*, Docket UE-901183-T and *In the Matter of the Petition of Puget Sound Power & Light Company for an Order Approving a Periodic Rate Adjustment Mechanism and Related Accounting*, Docket UE-901184-P, Third Supp. Order (April 1, 1991). This program was referred to as Periodic Rate Adjustment Mechanism or PRAM. The Commission monitored the program closely and, in 1993, determined it was achieving its primary goal of removing disincentives to the Company’s acquisition of energy efficiency. See *Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment of Residential Exchange Credits*, Docket UE-920433, *WUTC v. Puget Sound Power & Light Company*, Docket UE-920499 and *WUTC v. Puget Sound Power & Light Company*, Docket UE-921262 (consolidated), Eleventh Supp. Order at 10 (September 21, 1993). However, in 1995, at the Company’s request, the Commission approved discontinuance of the PRAM. See *WUTC v. Puget Sound Power & Light Co., Third Supp. Order Approving Stipulations; Rejecting Tariff Filing; Authorizing Refiling*, Docket UE-950618, at 6 (Sept. 21, 1995).

³³³ Rulemaking to Review Natural Gas Decoupling, Docket UG-050369, Notice of Withdrawal of Rulemaking (October 17, 2005).

³³⁴ See *WUTC v. PacifiCorp*, Docket UE-050684, Order 04, ¶¶ 108-110 (April 17, 2006); *In re Petition of Avista Corp. for an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated with the Mechanism*, Docket UG-060518, Order 04 (February 1, 2007); *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-060266 & UG-060267, Order 08, ¶¶ 53-69 (January 5, 2007); and *WUTC v. Cascade Natural Gas Corp.*, Docket UG-060256, Order 05, ¶¶ 67-85 (January 12, 2007).

³³⁵ See *In re WUTC Investigation into Energy Conservation Incentives*, Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, including Decoupling, To Encourage Utilities to Meet or Exceed Their Conservation Targets at (Nov. 4, 2010) (Decoupling Policy Statement).

both the company and its ratepayers.”³³⁶ By “decoupling” sales from revenues, a utility should no longer be encouraged to sell more energy, and conserve less, in order to earn more profit. Ending this so-called “throughput incentive” is the essence of a full decoupling mechanism.³³⁷

222 We approved full decoupling for PSE in 2013³³⁸ and for Avista in 2014.³³⁹ We invite such a proposal from Pacific Power and other parties in the Company’s next general rate case. We encourage Pacific Power to engage in meaningful discussion with Staff, Public Counsel, and other interested stakeholders and to develop a proposal.

b) Non-Residential Rates

223 The Company proposes several non-controversial changes to its non-residential rate design. For Schedule 48T and 48-T Dedicated Facilities, the Company proposes larger increases to demand charges than other portions of rates.³⁴⁰ Neither Boise White Paper nor Staff oppose the Company’s proposal for these schedules. For general service, agricultural pumping, and street lighting schedules, the Company proposes allocating more of the increase to demand rates in order to move cost components closer to cost of service.

224 Walmart proposes a substantial increase to demand charges and a substantial decrease in energy charges for Large General Service Schedule 36. Walmart argues that “Pacific Power’s current and proposed Schedule 36 charges are not reflective of the underlying cost of service and are disproportionately weighted towards collection of energy-related costs and, as a result, under collect demand-related costs.”³⁴¹ In

³³⁶ Decoupling Policy Statement ¶ 27.

³³⁷ See Regulatory Assistance Project, *Revenue Regulation and Decoupling: A Guide to Theory and Application*.

³³⁸ *In the Matter of the Petition of Puget Sound Energy, Inc. and NW Energy Coalition For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms*, Dockets UE-121697 and UG-121705, Order 06 (June 25, 2013).

³³⁹ *WUTC v. Avista Corporation*, Dockets UE-140188 and UG-140189, Order 05 (November 25, 2014).

³⁴⁰ Steward, Exh. No. JRS-1T at 29.

³⁴¹ Walmart Initial Brief ¶ 11 (citing *See Chriss*, Exh. No. SWC-1T at 11:10-18).

addition, Walmart argues Pacific Power's proposed charges for Schedule 36 inappropriately shift transmission and generation demand cost responsibility from lower load factor customers to higher load factor customers resulting in a misallocation of cost responsibility because higher load factor customers will overpay for the demand-related transmission and generation costs.³⁴² Walmart proposes four specific changes to Schedule 36 charges relative to the Company's tariff unbundling proposal:³⁴³

- Set the unbundled generation (non-NPC) demand charge and transmission demand charge at 50 percent of their cost-based levels.
- Accept the energy charge block structure and price ratio as proposed by Pacific Power.
- Reduce the generation (non-NPC) energy charge revenue requirement by an amount equal to the demand charge revenue requirement increase.
- Reflect any reductions in Schedule 36 revenue requirement from Pacific Power's filed proposal by reducing the generation (non-NPC) energy charges and transmission energy charges.³⁴⁴

225 On rebuttal, the Company provides a revised proposal for Schedule 36 that moves towards, but does not match, Walmart's proposal. Ms. Steward testifies that:

The Company agrees in part with Walmart's proposed rate design, however, the Company is proposing a more gradual movement in increasing the demand charge for Schedule 36 in light of bill impacts. Specifically, the Company proposes a movement that is half way between a rebuttal rate calculated the same as the original filing of \$3.49 or approximately 40 percent of total generation demand and Walmart's 50 percent generation demand proposal or \$4.38. The proposed rate of \$3.94 is approximately 45 percent of total generation

³⁴² *Id.* ¶ 12.

³⁴³ We discuss and reject the Company's unbundling proposal in the next section of this Order.

³⁴⁴ *Id.* ¶ 13 (citing Chriss, Exh. No. SWC-1T at 15:18-17:5).

demand costs. The transmission demand rate is calculated using the same approach as applied above but for transmission demand.³⁴⁵

226 *Commission Determination:* The principle of gradualism is an important consideration in making changes in rate design proposed by a commercial customer that will have a bill impact for the entire class of customers served under a given rate schedule. We accept Pacific Power's proposed changes to non-residential rate design, including the Company's revised proposal, on rebuttal, for Schedule 36 that is generally consistent with what Walmart recommends but implemented more gradually.

c) Unbundled Rates

227 Pacific Power proposes to unbundle rates in its tariffs by service function. The purpose, according to Ms. Steward is to make the costs associated with the different utility functions shown in the COSS (*i.e.*, generation, transmission, and distribution) more readily transparent in rates.³⁴⁶ None of the parties expressly object to the Company providing a more granular description of costs in its tariffs. Walmart, moreover, supports the idea and encourages the Company to show unbundled rates on its bills as well.³⁴⁷ Ms. Steward testifies that:

The Company supports increased transparency in rates and accordingly is willing to work with parties to add greater cost transparency on bills for non-residential customers through unbundled rates. For residential customer bills, it will be important to incorporate customer education prior to making changes on the bills in order to minimize customer confusion. As such, any roll out in reflecting unbundled rates on bills will need to be staggered between residential and non-residential customer bills.³⁴⁸

228 Describing the Company's concept of unbundling, Ms. Steward testifies that the Company includes the costs for customer services, billing, and meter reading from the

³⁴⁵ Steward, Exh. No. JRS-13T at 49:19-50:3.

³⁴⁶ Steward, Exh. No. JRS-1T at 2:13-16.

³⁴⁷ Walmart Initial Brief ¶ 10.

³⁴⁸ Steward, Exh. No. JRS-13T at 20:10-16.

cost of service study in the Distribution category.³⁴⁹ She says also that “[t]he type of rate component used—basic charge, demand charge, energy charge—depends on the type of functionalized cost and whether the costs are fixed or variable.”³⁵⁰ She explains the implications of this, from the Company’s perspective, in some detail, as follows:

Generation is comprised of both fixed (capacity or demand) and variable (energy) costs. As previously discussed, the cost of service study classifies costs between demand and energy using the west control area SDLF. Accordingly, the Company proposes to recover these costs through both energy and demand rates. The variable or net power costs are recovered through energy rates for all rate schedules, which is consistent with cost causation. While cost causation principles would support recovery of generation fixed costs through demand rates, not all customers currently have the metering capability for demand charges, or three-part rates (i.e., basic charges, demand charges and energy charges). For these customers, most fixed costs are currently recovered through energy rates. For the customers that currently do have three-part rates, current demand charges recover only a portion of the fixed generation costs. As discussed below, the Company is proposing larger increases to demand charges to better reflect cost causation; however, to avoid adverse impacts to low load factor customers, in this case the remainder of the allocated generation fixed costs continue to be recovered through energy charges.

Transmission costs are associated with the bulk transmission system that brings power from the generation source to the load centers. Transmission is also comprised of fixed cost and variable costs. It has been the Commission’s accepted practice to use the same classification methodology as used for generation to determine demand- and energy-related costs in the Transmission function in the cost of service study. Therefore, the Company proposes to recover these costs through both demand and energy rates for this case in a similar manner as described above for generation costs.

³⁴⁹ Steward, Exh. No. JRS-1T at 15:23-16:2.

³⁵⁰ *Id.* at 16:12-14.

Distribution costs (along with retail and miscellaneous) are fixed costs associated with the local facilities necessary to connect and serve individual customers. Accordingly, these costs should be recovered through the monthly basic charges and load size charges (which are based on demand measurements). For rate schedules that do not have three-part rates (where demand meters are not available for load size measurements), as described later the Company designed rates in this case to recover half of these costs through the basic charge and half through energy rates. For all other schedules, the Company proposes to recover these costs through the basic charges and load size charges.

229 *Commission Determination:* The Company does not make entirely clear why it is proposing unbundling rates in its tariffs along the lines described, but until the proposal is more fully vetted we are concerned that this is a first step in a direction the Commission may not wish to go. We find interesting, for example, that the Company actually proposes to bundle the costs normally categorized as “direct customer costs” (*i.e.*, customer services, billing, and meter reading) in the cost of service study, in the “Distribution” category. This is consistent with the Company’s proposal in this case to increase dramatically the basic charge to residential customers by adding distribution costs to the basic charge which ordinarily includes only direct customer costs. We earlier reject in this Order the Company’s proposed increase in the basic charge. Were we to accept the Company’s unbundling proposal, which in this instance amounts instead to a bundling proposal, this might signal acceptance of the idea that distribution costs are properly recovered in a basic charge. Looking at other evidence sponsored by the Company, this could lead to proposals to increase the residential basic charge to \$28 and then to \$47 so as to recover all fixed costs of distribution to residential customers through the basic charges. As we discuss above, a well-developed decoupling mechanism will address any issues the Company may have with respect to recovery of its fixed distribution costs.

230 Ms. Steward’s discussion of fixed and variable costs in connection with generation and transmission presents similar concerns. It appears that in Pacific Power’s view the only barriers to straight fixed-variable rate design are metering capabilities and three-part rates. Were we to accept the Company’s unbundling proposal, this might be taken as a signal that the Commission is prepared to move in the direction of such a rate design for all classes of customers. We are not.

231 Proposals such as these are more effectively considered in separate proceedings or in industry-wide discussions in workshops. We reject the Company's proposal to unbundle rates in its tariffs in the fashion described in Ms. Steward's testimony.

d) *Tariff Rule 11D and Tariff Schedule 300*

232 Pacific Power initially proposed to modify Section B of Rule 11D, *Field Visit Charge*, by adding language providing that the Company may assess such a charge if an action by a customer during a field visit prevents the Pacific Power employee from disconnecting or reconnecting the customer's meter.³⁵¹ In addition, Ms. Coughlin's direct testimony relates that the Company proposed to add language to Rule 11D to specify that individual customers are responsible for paying the collection agency costs associated with the collection of their unpaid debt, rather than having these costs recovered in rates.

233 *The* Company also proposes that a new charge, Non-Radio-Frequency Meter Accommodation, be added to Schedule 300. This new charge coincides with the proposed addition of non-radio-frequency meter accommodation language proposed for Rule 8. The "accommodation" is for customers who wish to have a meter that does not emit radio signals because they have concerns that such meters may affect their health. Pacific Power proposes to charge a one-time \$240 fee, ostensibly to cover installation and removal costs, and \$20 per month to have a field employee read the meter.

234 In addition, the Company proposes to modify the amounts for the following charges "to more closely align with the Company's costs to perform the work."³⁵²

- Connection Charge
- Reconnection Charge
- Unauthorized Reconnection/Tampering Charge
- Facilities Charge

³⁵¹ Coughlin, Exh. No. BAC-1T at 4:6-26.

³⁵² *Id.* at 11:16-21.

235 Ms. Steward testified for the Company on rebuttal that:

In response to concerns raised by the parties, the Company is willing to withdraw its proposal for the Collection Agency to charge the customer as reflected in the changes proposed for Rule 11D, its proposal for changes to the Field Visit Charge language in Rule 11D, and its proposal to increase the Connection Charge and Reconnection Charge. In doing so, an adjustment of \$83,324 to increase revenue requirement is being made.³⁵³

236 The Company continues to support the following proposed charges in Schedule 300:³⁵⁴

Proposed Changes to Schedule 300

Schedule 300 (Note 1)	Existing	Proposed
Rule 8: Non-Radio Frequency Meter Charge (new charge) ³⁵⁵	N/A	\$240 (+ \$20/ month)
Tampering/Unauthorized Reconnection Charge ³⁵⁶	\$75	\$110
Line Extension Facilities Charge (company's exp.) ³⁵⁷	1.67%	1.20%
Line Extension Facilities Charge (customer's exp.)	0.67%	0.60%
Transmission Facilities Charge (company's exp.)	0%	0.90%
Transmission Facilities Charge (customer's exp.)	0%	0.30%

(Note: Facilities charges are percentages of installed costs per month.)

³⁵³ Steward, Exh. No. 13T at 51:8-13. We note that this is the actual decrease in *pro forma* revenue, which must be adjusted by applying a conversion factor to arrive at the revenue requirement impact, \$87,440. Compare Siores, Exh. No. 10T at 3 (Table showing adjustments to revenue requirement indicates increases of \$87,440 for withdrawal of proposed Schedule 300 changes and \$44,138 for withdrawal of Collection Agency Fees).

³⁵⁴ Steward, Exh. No. JRS 13-T at 52:9-10. Ms. Steward also identifies the Company's proposed change in the description of the "Returned Check Charge", designating it instead as the "Returned Payment Charge" to be consistent with an earlier change in Rule 10, *Billing*.

³⁵⁵ Coughlin, Exh. No. BAC-1T at 3:2-9.

³⁵⁶ *Id.* at 17:12-23, 18:1-3.

³⁵⁷ *Id.* at 18:12-19:19.

Staff witness Roger Kouchi and Public Counsel witness Stefanie Johnson provided detailed testimony contesting the Company's proposed increases to connection and reconnection charges and changes to Rule 11D that the Company withdrew.

Although they do not address specifically the proposed new charge and fee modifications in Table 6, both witnesses recommend that the Commission reject the entire Adjustment 3.8 associated with Schedule 300 because Pacific Power failed to provide a detailed assessment of how these increases would impact low-income customers.³⁵⁸

237 *Commission Determination:* Pacific Power used the same method to calculate the unauthorized reconnection / tampering charge as it did to calculate the reconnection / connection charges that it withdrew. Moreover, the magnitude of the proposed change, a nearly 50 percent increase, is similarly significant. If approved, the proposed fee would be the highest in any of PacifiCorp's service territories.³⁵⁹ We are concerned, too, that Pacific Power failed to provide an assessment of how this fee increase would impact low-income customers. Thus, we reject the Company's proposed increase to the unauthorized reconnection / tampering charge for these reasons.

238 We also reject Pacific Power's proposed reduction to the distribution facilities charge and new facilities charge for transmission facilities. These charges are based on financial models, but Ms. Coughlin's testimony fails to provide adequate support for the cost assumptions used.³⁶⁰ Ms. Coughlin's calculations, for example, include a combined Federal and State Income rate, despite the fact that Washington does not have state income tax.³⁶¹ The record does not include sufficient evidence to support approval of the proposed change in the distribution facilities charge or the new transmission facilities charge.

239 Although it is a close call, we will accept, for purposes of this case, the proposed new fee for a Non-Radio Frequency Meter Charge. We allow the fees principally because they are linked to a new service that some customers may wish to have available. Ms.

³⁵⁸ Kouchi, Exh. No. RK-1T, at 28:6, Johnson, Exh. No. SAJ-1T at 12:7-9.

³⁵⁹ The current unauthorized reconnection / tampering charge is \$75 in all of the Company's service areas.

³⁶⁰ Coughlin, Exh. No. BAC-1T at 18:12-23.

³⁶¹ Coughlin, Exh. No. BAC-5.

Coughlin's testimony, however, falls short of demonstrating to our full satisfaction that the proposed fees are reasonable. It appears from her testimony that Company personnel will not perform this work efficiently.³⁶² In addition, the proposed fee does not compare favorably with significantly lower fees for the same service in other jurisdictions.³⁶³ The bases for these fees warrant further investigation and we expect to see a more fully developed record in the Company's next general rate case. We also expect our Staff to investigate fully the bases and support for this charge.

K. Low-Income Bill Assistance (LIBA)

240 *Pacific Power's* low-income customers continue to face difficult choices as they balance their needs for goods and services against their financial resources. Facing these issues in *Pacific Power's* 2011/2012 GRC, the Commission approved a settlement that included a five-year plan addressing low-income bill assistance.³⁶⁴ The plan includes four key elements:

- As a cost-cutting measure, a percentage of the Company's LIBA recipients will be certified every other year, as opposed to annually.
- The program will provide assistance to additional recipients.
- The LIBA eligibility certification fee paid to the community action agencies who administer LIBA will be incrementally increased.
- Funding for benefits received by LIBA participants will be increased to twice the amount of any rate increase authorized by the Commission for *Pacific Power*.³⁶⁵

241 *In this case*, *Pacific Power* proposed specific changes that are consistent with the five-year plan and are supported by the Energy Project.³⁶⁶

³⁶² TR. 515:8-12.

³⁶³ TR. 505:6-7.

³⁶⁴ *See WUTC v. Pacific Power*, Docket UE-111190, Order 07 ¶¶ 17-18 and 40-44 (March 30, 2012).

³⁶⁵ Eberdt, Exh. No. CME-1T at 3; 16-23.

³⁶⁶ Energy Project Initial Brief at 2; Eberdt, Exh. No. CME-1T at 4:13-5:2.

242 *Commission Determination:* While the issue of low-income bill assistance is not contested in this proceeding, we call it out for discussion and expressly approve the Company's proposal in this case because the matter is critically important and deserves close attention on a continuing basis. As we did in approving the five-year low-income bill assistance program in 2012, we again commend the Company and the other parties for their proactive endeavors and cooperative behavior in increasing funding to assist those most in need. The Commission's observation in its 2012 order bears repeating:

While many customers are adversely affected by an increase in their electricity rates, we recognize that the customers eligible for the LIBA program are the most dramatically affected by a rate increase and are the least capable of absorbing any rate increase in their monthly income. Accordingly, changes to the LIBA Program that reduce the administrative burden of annual certification and increase benefits should provide welcome respite to participating customers. Conversely, the increase to the Schedule 91 residential surcharge, eight cents per month, imposes a minimal burden on the customers funding the program.³⁶⁷

We encourage continued efforts by the Company, Staff, the Energy Project, and others who recognize the importance of ensuring that low-income customers have access to the vital services Pacific Power provides, to find innovative means to provide it.

L. Regulatory Assets and Liabilities (Deferral Accounts)

1. Merwin Fish Collector (Docket UE-140617)

243 The Commission rejected Pacific Power's request for recovery of costs associated with the Merwin Fish Collector Project (Merwin Project) in Docket UE-130043 because it was not expected to be in service and, hence, used and useful, until at least February 2014.³⁶⁸ The Commission also found that Pacific Power failed to present

³⁶⁷ *WUTC v. Pacific Power*, Docket UE-111190, Order 07 ¶ 42 (March 30, 2012).

³⁶⁸ Docket UE-130043, Order 05 ¶¶ 200, 203.

evidence that the costs of constructing the project met the known and measurable standard.³⁶⁹

- 244 The Merwin Project was placed in service on March 28, 2014, just over one month before Pacific Power filed this case.³⁷⁰ As discussed previously, the Company proposes to include the project in rate base as a post-test period major plant addition and the Commission approves that treatment. Just as in the case of any other plant addition found prudent and otherwise appropriate for inclusion in rate base, the Company will earn a return of its investment through depreciation expense and a return on its investment as of the effective date of new rates.
- 245 *Unlike other pro forma* additions to rate base, however, Pacific Power preserved its right to request special treatment by petitioning the Commission on April 14, 2014, in Docket UE-140617 to allow either recovery of costs through a separate tariff rider, or an accounting petition to defer those costs. The Commission rejected the tariff rider but granted the accounting petition for a deferral and consolidated Docket UE-140617 into Docket UE-140762.³⁷¹ In the context of this case, the Company proposes to recover the return of, and return on, the Merwin plant beginning as of the date of its deferral petition.³⁷² That is, the Company asks for both depreciation expense and return on rate base as if the Merwin plant had been approved for inclusion in rate base as of the date of its deferral accounting petition. Pacific Power also requests recovery of O&M costs associated with the Merwin Project from the date of its accounting petition. The impact of the Company's proposal on revenue requirement is \$1,875,489.³⁷³
- 246 *Staff* proposes the Commission allow the Company to recover the O&M expense and depreciation expense (*i.e.*, return of investment) included in the deferral but exclude

³⁶⁹ *Id.* ¶ 205.

³⁷⁰ Siores, Exh. No. NCS-10T 24:9-12.

³⁷¹ *WUTC v. Pacific Power & Light Co.*, Docket UE-140762, Order 03 (Order 01 of Docket UE-140617) (May 29, 2014).

³⁷² The Commission's approval of Pacific Power's deferral petition establishes an exception to the matching principle and the Company, when seeking recovery, thus avoids the prohibition against retroactive ratemaking for the costs authorized for deferral treatment.

³⁷³ Siores, Exh. No. NCS-14, at 5.

pre-tax return on rate base (*i.e.*, return of investment).³⁷⁴ Staff argues that its recommendation “balances competing policy concerns” by providing shareholders with recovery of depreciation expense and O&M expense incurred during the pendency of this rate proceeding (*i.e.*, between rate effective dates) while not allowing the Company’s to recover the return on its investment for the 13 months preceding the date the asset is authorized to be included in rate base. This removes the Company’s primary incentive for frequent accounting petitions that effectively add plant to rate base between rate cases.³⁷⁵

247 Boise White Paper opposes allowing any of the Merwin Project deferral costs for the same reason Staff proposes disallowing the return on equity component. Mr. Mullins testifies that deferral requests such as this one raise serious issues of equity and fairness. In particular, Mr. Mullins testifies that:

Customers do not control the timing of rate cases, nor do they have the information or the resources to file petitions requesting deferred accounting of *benefits* the Company receives between rate cases. Rather, customers rely on the regulatory compact and the oversight of the Commission’s rate case process to capture and balance both the costs and the benefits the Company realizes between rate cases. It would be unfair to allow PacifiCorp to shift responsibility for all of its expenses to customers through deferred accounting, while allowing the Company to enjoy the benefits it receives until such a time as it chooses to file a rate case.³⁷⁶

Boise White Paper argues the Company’s request for special treatment of the Merwin Project “is simply unnecessary and harmful to customers, given the

³⁷⁴ Ball, Exh. No. JLB-1T at 25:13-19.

³⁷⁵ Staff Initial Brief ¶ 145. Mr. Ball testifies that “[t]he Commission has previously expressed concern with inter-period adjustments to rate base and Staff shares those concerns.” Ball, Exh. No. JLB-1T at 27:13-14. The Commission’s primary concern is that granting such adjustments provides an incentive for frequent deferral accounting petitions.

³⁷⁶ Mullins, Exh. BGM-1CTr at 70:21-71:2 (quoting ICNU Comments on Petition of PacifiCorp, Docket No. UE-140617 at 4 (May 27, 2014)).

return and depreciation treatment already available to the Company in the normal rate base mechanism.”³⁷⁷

248 Public Counsel also opposes approval of any part of Pacific Power’s request to recover deferred Merwin Project costs, essentially for the same reasons as Boise White Paper. Public Counsel argues that cost recovery between rate cases “violates the general restriction on single-issue ratemaking.”³⁷⁸ He argues that the Company has not established a basis for an exception to this doctrine and that it is neither fair nor reasonable to single out the Merwin Project for special treatment between rate cases. It is enough, in Public Counsel’s view, to include the Merwin Project plant in rate base just like any other *pro forma* major plant addition, which allows for “the reasonable and sufficient recovery of Merwin Project costs.”³⁷⁹

249 *Commission Determination:* While not unique, the Merwin Project is of a type that is unusual. The installation of this fish collector was necessary for the Company to secure a new Federal Energy Regulatory Commission (FERC) license, which will allow the Company to continue to operate the Lewis River dams for an additional 50 years.³⁸⁰ The project’s design was dictated and approved by federal regulators.³⁸¹ Because of this project, albeit not revenue producing itself, customers will continue to benefit from the Company’s emission-free, low-cost hydropower generation.³⁸²

250 Staff refers us to a somewhat similar situation that confronted Avista, leading the company to file a petition for an accounting order to defer costs related to the improvement of dissolved oxygen levels in Lake Spokane.³⁸³ This project was also part of a FERC licensing process and also involved the Washington Department of Ecology. Avista recorded its costs for the project as Construction Work in Progress. It intended to capitalize the costs after construction of a facility that was anticipated to be required as part of an attainment plan. Once a non-facility based plan was

³⁷⁷ Boise White Paper Initial Brief ¶ 105.

³⁷⁸ Public Counsel Initial Brief ¶ 79.

³⁷⁹ *Id.* ¶ 80.

³⁸⁰ Docket UE-130043, Order 05 ¶ 196.

³⁸¹ *Id.*

³⁸² *Id.*

³⁸³ Petition of Avista Corporation, Docket UE-131576, Order 01 ¶ 1.

approved, however, Avista requested deferral accounting treatment for its costs with the intention to seek a determination of eligibility for recovery “in their next general rate case or in a separate filing.”³⁸⁴ Avista did not seek and the Commission did not authorize the accrual of interest (*i.e.*, return on investment) on the Washington share of the deferrals.³⁸⁵

251 While a close call, the approach taken in the Avista case provides guidance and influences us to accept Staff’s recommendation with respect to the Merwin Project deferral. We take seriously the concerns Staff, Public Counsel, and Boise White Paper raise with respect to the importance of discouraging companies from filing accounting petitions as a means to secure between-rate-case cost recovery for plant additions. We are nearly persuaded to reject Pacific Power’s request for recovery of any of these costs and to treat the Merwin Project just as any other post test period *pro forma* adjustment to rate base. We emphasize, then, that the treatment we allow in this instance is exceptional and turns on the unusual nature of the project involved. We authorize recovery of the Merwin Project’s deferred O&M costs and depreciation from the date of the Company’s deferral petition through the day preceding the rate effective date of Pacific Power’s compliance filing in Docket UE-140762. This deferral will allow the Company to recover \$530,000 in such costs, but exclude any deferred interest. The recovery will be through Pacific Power’s Tariff Schedule 92. Pacific Power is authorized to include the Merwin Project in rate base and will recover return on, in addition to return of, its investment prospectively, beginning on the rate effective date.

2. Colstrip Outage (Docket UE-131384)

252 Pacific Power filed a petition for an accounting order on July 26, 2013, in Docket UE-131384, requesting an order authorizing the Company to defer from the date of the petition forward its costs for repair and replacement purchase power for an outage at the 740-megawatt unit 4 of the Colstrip generating plant located in Colstrip, Montana.³⁸⁶ The petition followed a major plant failure on July 1, 2013, resulting in material damage to the unit. The Company estimated the costs to repair the plant

³⁸⁴ *Id.* ¶ 5.

³⁸⁵ *Id.*

³⁸⁶ Petition for an Accounting Order, Docket UE-131384, (July 23, 2013) at ¶ 1.

would range between \$3 million to \$4 million and was expected to take at least six months to complete.³⁸⁷

- 253 Although we have found no related discussion in the record, it appears from a comparison of Ms. Siores' direct and rebuttal exhibits that the Company removed the costs of repair from its deferral accounting,³⁸⁸ leaving only a request to defer replacement power costs. We presume this means the Company now elects to recover the costs of repair as a capital cost in base rates, rather than through a Schedule 92 surcharge addition.
- 254 The Company estimates that additional power purchases required to replace the lost energy normally obtained from the damaged unit range from \$9 million to \$12 million over the anticipated term of the outage.³⁸⁹ The Company requests deferral accounting treatment for the replacement power costs, and for recovery of the deferred costs in base rates.
- 255 On June, 24, 2014, without acting on the petition, the Commission consolidated Docket UE-131384 into this general rate case in Docket UE-140762.³⁹⁰ In the context of the consolidated cases the Commission must determine whether to grant the petition and, if so, whether to allow recovery of the deferred costs.
- 256 The Company's only mention of the deferral in its direct testimony is that its initial filing in UE-131384 is consistent with Staff testimony in Docket UE-080220. It was in that proceeding that Staff recommended the company file an accounting petition to request deferral and possible recovery of excess costs resulting from extended forced outages.³⁹¹
- 257 *Staff's* witness, Ms. Erdahl, does not oppose the proposed deferral and recovery of both the repair and the replacement power costs, but recommends that they be

³⁸⁷ *Id.* ¶ 4.

³⁸⁸ Compare Exh. No. NCS-9 at 1-3 to NCS-14 1-2.

³⁸⁹ *Id.* ¶ 5.

³⁹⁰ Docket UE-140672, Order 01 (June 24, 2014).

³⁹¹ Dalley, Exh. No. RBD-1T at 7:5-11.

recovered without recognition of an interest component.³⁹² Additionally, under Staff's approach, the Company's recovery of the deferred costs would be as an element of the revenue requirement model, embedded in base rates, not as a component of the Company's proposed Schedule 92.³⁹³

258 The Company opposes Staff's recommendation that no interest be allowed if the petition is approved and deferral accounting is authorized. Ms. Siores testifies that removal of interest expense does not account for the time value of money which means the financing costs on any deferred amounts will not be recovered.³⁹⁴ Ms. Siores does not address Ms. Erdahl's objection that the Company's approach enables earning interest on revenue-sensitive taxes.

259 *In* response to Staff's position that a separate tariff not be used to collect the deferral, Ms. Siores maintains that once the amounts are fully amortized, collection under the separate tariff rider will cease, whereas if the deferrals are included in the permanent rates the Company will continue to collect the rates until the next rate case.³⁹⁵

260 Mr. Mullins opposes deferral and recovery of any Colstrip cost because, in his opinion, the outage was not an extraordinary event.³⁹⁶ Mr. Mullins also claims that the Company has failed to provide any updated estimated costs incurred, a point Ms. Siores rebuts in her testimony. According to Ms. Siores, the Company provided updates in its initial filing, showing actual costs, in her exhibit NCS-9.³⁹⁷

261 Mr. Mullins testifies that it is the Company's failure to gain approval of a properly designed PCAM, which the Commission has more than once invited it to file, that now should prevent it from deferring and recovering the costs of replacement power.³⁹⁸ Mr. Mullins argues in addition that the Company should not be allowed to defer and recover its costs because, in his view, the Colstrip failure is directly

³⁹² Erdahl, Exh. No. BAE-1T at 11:10-16.

³⁹³ *Id.* at 11:1-7.

³⁹⁴ Siores, Exh. No. NCS-10T at 21:16-19.

³⁹⁵ *Id.* at 21:20-22:2.

³⁹⁶ Mullins, Exh. No. BGM-1CT at 62:11-66:18.

³⁹⁷ Siores, Exh. No. NCS-10T at 22:7-11.

³⁹⁸ Mullins, Exh. No. BGM-1T at 62:12-63:5.

attributable to the plant's operator as a result of faulty repair work done at the time of the prior outage. Mr. Mullins contends the costs attributable to this latest failure are more properly recovered from the operator and not Washington rate payers.³⁹⁹

262 Mr. Ralston, in rebuttal testimony for Pacific Power, disputes Boise White Paper's contention that the Colstrip operator was imprudent. Mr. Ralston testifies that the fact that the root cause scenario could not identify with certainty the cause of the outage, does not support a conclusion that the operator was not at fault.⁴⁰⁰ Focusing on the failure report an outside expert prepared for the Company, Mr. Ralston testifies:

Boise suggests that factual evidence available was not adequate to develop a failure cause and that concrete evidence and a clear indication of failure must be present to show the Company's actions were prudent. However, the failure report was very detailed and used all the information available, including plant logs, relay and alarm data, and physical inspections of the damage by industry experts. Boise discounts the statement by the external root cause investigating team that, "[i]n our opinion, PPL did everything according to standard industry practice such as hiring the OEM (Siemens) to perform the maintenance, performing El Cid testing on the core, operating their unit according to industry practice, (since there was no indication of mis-operation), and protecting the unit with adequate relay protection. Nothing they did or could have done, could have prevented this failure." This statement, along with the rest of the report, demonstrates that the Company acted prudently and took all recommended steps to maintain the equipment as per the OEM recommendations.⁴⁰¹

Mr. Ralston concludes that: "Boise's claim is speculation unsupported by the expert analysis in the root cause report."⁴⁰²

263 *Commission Determination:* We deny Pacific Power's accounting petition. The replacement power costs in question do not qualify as extraordinary costs such as might arguably be candidates for deferral accounting. As recently as Pacific Power's

³⁹⁹ *Id.* at 64:16-66:18.

⁴⁰⁰ Ralston, Exh. No. DMR-2T at 8:15-17.

⁴⁰¹ *Id.* at 9:1-13.

⁴⁰² *Id.* at 10:1-2.

2012/2013 GRC, the Commission made clear its preference for a properly designed PCAM that addresses all of the Company's power costs, not a single element. Order 05 also expresses the Commission's objections to power cost recovery mechanisms that are nothing more than trackers. Pacific Power's deferral request here is nothing more than a single element power cost tracker. As previously discussed, the Commission, through this Order, will require Pacific Power to file tariff sheets implementing a properly designed PCAM along the lines of Staff's proposal in this case. Once in place, this will resolve power cost recovery issues such as those presented in Docket UE-131384.

3. Hydropower Deferral (Docket UE-140094)

264 Pacific Power filed a petition for an accounting order in Docket UE-140094 on January 17, 2014, seeking to defer costs that the Company anticipated it would incur during 2014 due to decreased hydropower production (hydro). Pacific Power requested specifically an order authorizing the Company to defer from the date of its petition forward any increased power costs caused by declines in hydro generation, due to abnormally dry weather conditions. Pacific Power sought deferral of these costs to track and preserve them for later ratemaking treatment.

265 On June, 24, 2014, without acting on the petition, the Commission consolidated Docket UE-140094 into this general rate case.⁴⁰³ In the context of the consolidated cases the Commission must determine whether to grant the petition and, if so, whether to allow recovery of the deferred costs.

266 Pacific Power's petition states that "significant declines in hydro generation due to abnormally dry weather conditions and low water availability" would cause the Company "to make market purchases and rely on more thermal generation to compensate for the shortfall," expected to be in the range of \$15 million. Pacific Power presented no evidence with its petition demonstrating the asserted "significant declines" or their magnitude. Nor did Pacific Power present evidence demonstrating any "abnormally dry weather conditions and low water availability" record during periods leading up to the time of its petition in January 2014. Nor did the Company present evidence, other than its bare assertion, projecting that such claimed conditions would persist through the remainder of 2014 or, indeed, for any period of time.

⁴⁰³ Docket UE-140672, Order 01 (June 24, 2014).

- 267 In this case, Pacific Power seeks not only authority to defer these costs, but also proposes to recover \$2.4 million in increased costs the Company claims were caused by lower than forecast hydropower during 2014.⁴⁰⁴ When this is compared with the \$15 million amount suggested in support of the Company’s petition, it appears the anticipated conditions, in fact, did not materialize as anticipated.
- 268 The only testimony the Company offers on this issue in its direct case is by Mr. Dalley in a single sentence stating: “The hydro deferral request is consistent with Commission precedent in Docket UE-080220.”⁴⁰⁵ Docket UE-080220, however, was resolved on the basis of a settlement among the parties that by its own terms, as approved by the Commission, does not establish precedent in any sense of the word.⁴⁰⁶
- 269 The Company did not present testimony demonstrating significant declines in hydro generation during 2014 either in its deferral petition or in its direct case. Mr. Gomez, for Staff, analyzed the Company’s hydro generator performance-based in part on the Company’s responses to two data requests – one submitted by Public Counsel and one submitted by Staff.⁴⁰⁷ According to Staff, “actual hydro generation (January – August 2014)” when combined with the Company’s forecast for the “remainder of the proposed deferral period (September- December 2014),” shows hydro generator output within 2.9 percent of the amount placed into rates.⁴⁰⁸ This result was better

⁴⁰⁴ Duvall, Exh. No. GND-4T at 62:8-10.

⁴⁰⁵ Dalley, Exh. No. RBD-1T at 7:10-11 (citing *Wash. Utils. & Transp. Comm’n v. Pacific Power & Light Co.*, Docket UE-080220, Order 05 (Oct. 8, 2008) (approving a settlement allowing amortization of a portion of the Company’s 2005 hydro deferral).

⁴⁰⁶ The Settlement Stipulation, attached to, and made part of, Order 05 provides in Section L.6. that the agreement is entered into “to avoid further expense, inconvenience, uncertainty and delay.” This provision continues with the statement that:

By executing this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed in arriving at the terms of this Stipulation, *nor shall any Party be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.*”

Wash. Utils. & Transp. Comm’n v. Pacific Power & Light Co., Docket UE-080220, Order 05, Attachment ¶ 33 (Oct. 8, 2008) (*emphasis added*).

⁴⁰⁷ Gomez, Exh. No. DCG-1CT at 17:6-7 and 10-12.

⁴⁰⁸ Staff Initial Brief ¶ 85 (citing Gomez, Exh. No. DCG-1CT at 17:6-10).

than the Company's experience from 2007 to 2013 when the difference between actual hydropower generation and the amount in rates averaged about 9 percent.⁴⁰⁹ Mr. Gomez concluded that the Company's hydro performance during the deferral period (2.9 percent as compared with 9.0 percent) was "well within an acceptable range."⁴¹⁰

270 In Mr. Duvall's rebuttal testimony, the Company updated its analysis of its hydro output, and represents that the difference between actual hydro generation and the amount in rates would be "approximately 7.6 percent" for all of 2014. Staff argues that even accepting this data, "the Company's actual hydro generation still falls within Staff's acceptable range of 9 percent of forecast."⁴¹¹ In a similar vein, Mr. Mullins testifies that despite early concerns that hydro conditions during 2014 would be below average for the calendar year, "the Northwest experienced higher than average spring precipitation, which has resulted in Northwest hydro conditions that are about normal."⁴¹²

271 Mr. Mullins also testifies that the Commission should reject the Company's deferred accounting proposal because it is one-sided.⁴¹³ As he explains it:

The Company forecasts hydro output in the GRID model based on median generation of a historical period. Accordingly, half of the time hydro generation is expected to be lower than the Company's forecast, and half of the time it is expected to be higher. In this case, the Company is seeking deferred accounting for costs associated with hydro generation that it originally expected to be below the median forecast; yet, the Company has not made similar proposals when hydro generation has been greater than the median.⁴¹⁴

⁴⁰⁹ *Id.* (citing Gomez, Exh. No. DCG-1CT at 17, see Footnote 28).

⁴¹⁰ Gomez, Exh. No. DCG-1CT at 17:10-11.

⁴¹¹ Staff Initial Brief ¶ 85.

⁴¹² Mullins, Exh. No. BGM-1CT at 67:5-12.

⁴¹³ *Id.* at 67:16.

⁴¹⁴ *Id.* at 67:17-22.

Mr. Mullins cites 2011 and 2012 as examples, observing that “when the spring run-off was well above the median, the Company made no effort to return the savings attributable to the higher than average hydro conditions.”⁴¹⁵

272 Staff, referring to the Company’s proposal as a “Hydro Tracker,” says that the Company seeks to recover ordinary variability in power costs, shielding itself entirely from the effects of weather, resulting hydro conditions, and changes in fuel costs.⁴¹⁶ Staff argues that the Commission previously has rejected the inclusion of normal hydro variability in power cost adjustment mechanisms. Indeed, as recently as Order 05 in Docket UE-130043 the Commission said:

PacifiCorp, however, proposes a PCAM that would protect the Company from any risk of under-recovery, even that due to the ordinary variability in power costs due to normal and foreseeable changes in fuel costs, ordinary variance in hydro conditions, normal variations in weather, and so forth. As the Commission previously observed in connection with such a proposal: “This would mark a new and much expanded role for the PCA.”⁴¹⁷

Staff asserts that despite such clear Commission guidance, the Company here seeks identical but narrower relief through its Hydro Tracker.

273 *Commission Determination:* We deny Pacific Power’s petition for an accounting order and, consequently, its proposed recovery in rates of any costs it would otherwise be authorized to book as deferred power costs. These costs are in no sense “extraordinary,” a criterion that should apply to a cost deferral accounting mechanism at the time requested and at the time any recovery is sought.

274 As stated previously, we do not favor narrow, single purpose trackers that use deferral accounting to recover on a dollar-for-dollar basis all variations in wholesale power costs, whether or not such variations are outside of the Company’s control. Instead, as the Commission has stated clearly in prior orders, such issues should be examined on the basis of the Company’s total portfolio of resources, and include mechanisms to

⁴¹⁵ *Id.* at 67:22-24.

⁴¹⁶ Staff Initial Brief ¶ 89 (citing Gomez, Exh. No. DCG-1CT at 17:17-20 and at 18:1-3).

⁴¹⁷ Docket UE-130043, Order 05 ¶172.

protect customers as well as promoting the Company's ability to recover such costs in a timely manner.

275 As previously discussed in this Order, we require Pacific Power to file tariff sheets implementing a properly designed PCAM along the lines of Staff's proposal in this case. Once in place, this will resolve power cost recovery issues such as those presented in Docket UE-140094.

4. Depreciation Deferral

276 On December 31, 2013, Pacific Power filed a petition in Docket UE-132350 seeking to defer a reduction in depreciation expense resulting from the difference in depreciation rates that were approved in Docket UE-130052 and the amount of depreciation expense used for setting rates in Docket UE-130043. In Order 01 of UE-132350, the Commission allowed the Company to defer the one-time reduction of depreciation expense of \$669,000 until such time as the deferred amount could be refunded through an appropriate adjustment to rates in Pacific Power's subsequent GRC, which is this proceeding. The Company, recognizing the increased deferral balance since the original filing, reflects the total reduction to revenue requirement for the rate year of \$877,345.⁴¹⁸

277 Staff agrees with the refund calculation reflecting the increased balance of the deferral, but Staff disagrees with the use of a separate tariff rider as the mechanism for the refunding the over-collection of depreciation expense. Instead of handling it through Schedule 92 as the Company proposes, Staff proposes to recognize the impact of the credit to customers as a reduction to revenues in the overall revenue requirement model.⁴¹⁹

278 In response, Ms. Siores testifies that once the deferred amount is fully amortized, the credit under Schedule 92 will cease, whereas if the deferrals are included in permanent rates as Staff suggests, this will not occur until adjusted out of rates in a future rate case.⁴²⁰

⁴¹⁸ Siores, Exh. No. NCS-14 at 3.

⁴¹⁹ Erdahl, Exh. No. BAE-1T at 11:3-8.

⁴²⁰ Siores, Exh. No. NCS-10T at 22:3-7.

279 *Commission Determination:* The deferral amount is not contested and we approve its
recovery as a credit to customers reflected in Schedule 92.

FINDINGS OF FACT

280 Having discussed above in detail the evidence received in this proceeding concerning
all material matters, and having stated findings and conclusions upon issues in dispute
among the parties and the reasons therefore, the Commission now makes and enters
the following summary of those facts, incorporating by reference pertinent portions of
the preceding detailed findings:

- 281 (1) The Washington Utilities and Transportation Commission is an agency of the
State of Washington, vested by statute with authority to regulate rates, rules,
regulations, practices, and accounts of public service companies, including
electrical and gas companies.
- 282 (2) Pacific Power is a “public service company” and an “electrical company,” as
these terms are defined in RCW 80.04.010 and as these terms otherwise are
used in Title 80 RCW. Pacific Power is engaged in Washington State in the
business of supplying utility services and commodities to the public for
compensation.
- 283 (3) Pacific Power’s current rates do not yield sufficient compensation for the
electric services it provides in Washington.
- 284 (4) Pacific Power requires relief with respect to the rates it charges for electric
service provided in Washington State so that it can recover its electric service
revenue deficiencies.
- 285 (5) The record supports a capital structure and costs of capital, which together
produce an overall rate of return of 7.30 percent, as set forth in the body of this
Order in Table 2.
- 286 (6) The Commission’s resolution of the disputed issues in this proceeding,
identified in Appendix A to this Order, coupled with its determination that
certain uncontested adjustments identified in Appendix B to this Order, and
taking into account the Commission’s determinations of the consolidated
dockets concerning deferrals as shown in Appendix C, are reasonable, results

in our finding that Pacific Power's electric revenue deficiency is \$9,568,464, as set forth in detail in Table 3, in the body of this Order.

- 287 (7) Applying the requirements of the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012 results in appropriate adjustments that enhance support for the Company's programs for low-income customers.
- 288 (8) The rates, terms, and conditions of service that result from this Order are fair, just, reasonable, and sufficient.
- 289 (9) The rates, terms, and conditions of service that result from this Order are neither unduly preferential nor discriminatory.

CONCLUSIONS OF LAW

- 290 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:
- 291 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.
- 292 (2) Pacific Power failed to show that the rates it proposed by tariff revisions filed on May 1, 2014, which were suspended by prior Commission order, are fair, just or reasonable. These as-filed rates accordingly should be rejected.
- 293 (3) Pacific Power carried its burden to prove that its existing rates for electric service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.
- 294 (4) Pacific Power requires relief with respect to the rates it charges for electric service provided in Washington State.
- 295 (5) The Commission must determine the fair, just, reasonable, and sufficient rates to be observed and in force under Pacific Power's tariffs that govern its rates,

terms, and conditions of service for providing electricity to customers in Washington State.

- 296 (6) The costs of Pacific Power's investments found on the record in this proceeding to have been prudently made and reasonable should be allowed for recovery in rates.
- 297 (7) Pacific Power should have the opportunity to earn an overall rate of return of 7.30 percent based on the capital structure and costs of capital set forth in the body of this Order.
- 298 (8) Pacific Power should be authorized and required to make a compliance filing to recover its revenue deficiency of \$9,568,464 for electrical service provided to its customers in Washington.
- 299 (9) The Commission should reject rate design proposals to increase substantially basic charges to residential customers. The Commission should otherwise make adjustments to the Company's cost of service, rate spread, and rate design as discussed in the body of this Order.
- 300 (10) Pacific Power should be authorized to increase funding for the Company's Low Income Bill Assistance Program as provided by the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012.
- 301 (11) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.
- 302 (12) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.
- 303 (13) Pacific Power, following additional process, should be required to file tariff sheets to make effective a Power Cost Adjustment Mechanism that is consistent with the Commission's design preferences, including among other things, appropriate dead bands and sharing bands that balance risk between the Company and its customers.

- 304 (14) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.
- 305 (15) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

- 306 (1) The proposed tariff revisions Pacific Power filed on May 1, 2014, which were suspended by prior Commission order, are rejected.
- 307 (2) Pacific Power is authorized and required to file tariff sheets that are necessary and sufficient to effectuate the terms of this Order, including determinations of a revenue deficiency of \$9,568,464 for electrical service. Pacific Power must file the required tariff sheets at least two full business days prior to their stated effective date, which shall be no sooner than April 1, 2015.
- 308 (3) Pacific Power is authorized and required to increase funding for the Company's Low Income Bill Assistance Program as provided by the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012.
- 309 (4) Pacific Power is required to participate in further proceedings in this docket to develop fully, and implement by filing appropriate tariff sheets, a Power Cost Adjustment Mechanism designed to be consistent with guidance the Commission has given in prior orders, as discussed in the body of this Order.
- 310 (5) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

311 (6) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective March 25, 2015.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

PHILIP B. JONES, Commissioner

ANN E. RENDAHL, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

Commissioner Jones' Separate Statement on Rate Design

- 312 I concur with the Majority with the end result in rate design, but write separately to express my differences with the tenor and rationale in our rejection of both the Company's and Staff's proposals. At the outset, I wish to reiterate that the burden remains with the Company to develop a just and reasonable rate design, and reflect the traditional regulatory principles of fairness and gradualism when spreading costs among customers. Staff and the stakeholders have an obligation to respond in good faith to the utility's proposals, but ultimately Pacific Power must provide sufficient facts and rationale to justify its proposals.
- 313 I differ with the Majority, however, in encouraging the Company to put forward a full decoupling proposal as the preferred option. Although it doesn't require Pacific Power to file such a proposal in the next GRC, its critique of the Company and Staff's proposals in this case, and frequent references to our Decoupling Policy Statement and adoption by PSE and Avista, certainly lead one to that conclusion. Essentially, the Majority appears to argue that the other two electric utilities have adopted full electric decoupling, it is working well, hence Pacific Power should do so as well. We appear to have taken on the role of the teacher who disciplines the disobedient child in the back of the classroom who is causing trouble to step forward to the front of the class and join the exemplary students, in other words, by adopting decoupling. I am not an opponent of decoupling, depending on its detailed design and structures, and have supported its adoption by PSE and Avista. Furthermore, I think the Commission can benefit by assessing different regulatory mechanisms to address flat load growth and potential attrition; a one-size-fits-all approach is not necessarily the best approach.
- 314 Rate design is a complex issue that attempts to do many things simultaneously, such as reflect fairness among customers, cost causation, adjust to changing utility loads and sources of generation, encourage certain public policy preferences, and protect low-income consumers. This is a very challenging and difficult balance to achieve. In my view, most observers have been aware for many years that most rate design structures do not truly reflect the true, actual costs of serving the various rate classes, especially in the balance between fixed (basic charge) and volumetric (per kilowatt-hour) rates. But most Commissions, including the UTC, have chosen to maintain the current rate design structures for the reasons cited above, namely fairness and gradualism. In this case, the Company proposes a significant increase in the residential basic charge, a dramatic shift away from the traditional residential rate

design approved by this Commission over the past decade. In short, the Company has not satisfied its burden in this case to provide evidence and rationale supporting the change.

315 At the same time, I commend the Company and the Staff for setting forth comprehensive, detailed proposals on residential rate design here. The utility business model is evolving quickly in response to changes in technology, energy efficiency, and customer-owned generation, although at different speeds among utilities. Moreover, our Legislature (and many other legislatures throughout the country) and other external stakeholders have focused on these issues and have been developing a variety of proposals at the state level. In response, the Commission has been spending a good deal of time and energy studying and developing broad policy recommendations on these issues in responding to questions and concerns from the Legislature.⁴²¹ Although I conclude that these two proposals from the Company and Staff are not sufficiently developed and vetted, the Commission has benefited from the exercise of reviewing and assessing these specific proposals. However, it is premature to act at this time and on this record for the following reasons. First, the Company, at a senior management level, has to favor decoupling as a mechanism to address issues like attrition, lost margins from conservation, or lost revenues from customer-owned generation. Moreover, it has to have a strong belief in decoupling, compared to other mechanisms, in order to succeed in getting the proposal through a contentious, fact-based regulatory process with other stakeholders. With PSE, we engaged in a multi-year “conversation” about decoupling in which the Company attempted at least twice to persuade us to adopt decoupling proposals, and senior management and Board members were actively engaged. Finally, PSE brought forward an acceptable proposal to us that we adopted as a multi-year pilot in the context of a complex settlement agreement. With Avista, we engaged in a similar process that began with a limited decoupling proposal for natural gas, and resulted in full electric and gas decoupling proposals in the context of a settlement agreement.

⁴²¹ *Study of the Potential for Distributed Energy in Washington State*, Docket UE-110667, Report on the Potential for Cost-Effective Distributed Generation in Areas Served by Investor-Owned Utilities in Washington State (October 7, 2011); *In the Matter of Amending and Repealing Rules in WAC 480-108 Relating to Electric Companies-Interconnection With Electric Generators*, Docket UE-112133, Interpretive Statement Concerning Commission Jurisdiction and Regulation of Third-Party Owners of Net Metering Facilities (July 30, 2014).

- 316 The context is markedly different with Pacific Power, and its parent company Berkshire Hathaway Energy (BHE). The Company is neutral at best on decoupling mechanisms, and doesn't appear to favor them as the proper mechanism to address issues specific to its cost structure and service territory. In our 2010 proceeding that led to the development of the Decoupling Policy Statement, in fact, the Company responded to the Commission's request for comment on potential mechanisms to address lost revenues and recovery of its fixed costs, namely: decoupling, a lost margin adjustment mechanism, straight fixed variable design (including an increase in the basic charge), and an attrition adjustment.
- 317 Of the mechanisms discussed, Pacific Power was the most supportive of either a lost margin recovery mechanism, straight-fixed variable rate design (increase in basic charge, decrease in volumetric charge), or some type of attrition adjustment.⁴²² Regarding a decoupling mechanism, it stated it was "neutral" and mentioned the drawbacks of such a proposal without offering much detail. Since that time, we have not engaged with the senior management of Pacific Power on these issues, and they have never expressed a whit of support for decoupling. Certainly, in this case the Company did not advocate at all for a decoupling mechanism; instead, it advocated for an increase in the residential basic charge to \$14. Since the burden ultimately remains with the Company to justify its proposals, I remain cautious about trying to either encourage or impose any specific regulatory mechanism, such as decoupling, without further process and deliberation.
- 318 The specific proposals of the Company and the Staff raise a number of questions that I think need to be answered more fully before moving forward, including but not limited to:
- The Company argues that the residential basic charge should include the fixed costs of the distribution system.⁴²³ This would include the cost of poles, wires, and line transformers – which traditionally have not been included in the basic charge – in addition to metering, service drop, and customer billing costs traditionally included in the basic

⁴²² *In re WUTC Investigation into Energy Conservation Incentives*, Docket U-100522, Comments of Pacific Power (July 14, 2010).

⁴²³ Steward, Exh. No. JRS-1T, at 19:1-14, and JRS-13T, at 22, 15-23, and 23, 1-6. She asserts that its estimate of the costs for what the Company defines as "local distribution and retail service costs" to be \$28 per month, of which the Company argues about one-half, or \$14, should be included in the basic charge.

charge. Other Parties disagree with the inclusion of distribution system costs in the basic charge, and challenge Pacific Power's classification of these costs as "fixed". Hence, I think the inclusion of distribution system costs in the basic charge, and their classification as either "fixed" or "variable" need to be examined further;

- Staff, to its credit, makes an interesting proposal for the addition of a third volumetric block in an inverted rate block design that would start at 1701 kWh per month, at a cost of approximately 12 cents/kWh. This is an intriguing proposal, but needs more vetting. In the context of a proposal to add a third volumetric block, I would like to see further analysis of price elasticity effects, the amount of "fixed costs" (however defined) included in such a third Block, and the impact on low-income customers. Additionally, rate design experts should continue to explore other options than a third block with decoupling, building upon the various scenarios the Company developed for residential rate design in preparation for the current rate case;
- Overall impact on low-income customers: the Energy Project makes some good points on the potential impacts of rate design proposals on low-income customers, and some of the unique characteristics of that population in Pacific Power's service territory. Although Staff rebutted some of these criticisms in its analysis and offered an alternative low-income basic charge of \$8.75, I think this analysis needs further refinement. I also encourage the Energy Project to engage fully with Staff and the Company on these issues, and offer specific alternatives in the recognition that changes in residential rate design are likely to occur sooner rather than later.
- The Company makes repeated references to the growing impact caused by more customer-owned generation in its service territory, but admitted that currently only 244 customers are self-generating with net metering. If this appears to be such a "threat" to the Company's revenues and margins, it needs to make a better case of what estimates or projections it is using.

These are just a few of the many questions that must be addressed and answered more fully in the next rate case that the Company prepares for the Commission. I am open to considering any specific mechanism that the Company wishes to propose for residential rate design; or if the Company prefers, propose one "primary" mechanism, and one "alternative" mechanism for the Commission to consider specifically in the

next case. But I reiterate that any proposal needs to be properly supported, balanced, and answer some of the questions and concerns noted above.

319 Meanwhile, as stated above, we are engaging with all electric utilities and stakeholders in our ongoing Collaborative on Distributed Generation and plan to hold a workshop on methods for addressing attrition in April. Since our Legislature and many external stakeholders are engaged in these issues, these fora are the ideal way for Pacific Power and other utilities to engage directly with the Commissioners and Staff on both policy and regulatory issues. I encourage the new senior management of Pacific Power to engage constructively in these collaborative discussions, and propose various alternatives for us and other stakeholders to assess before proceeding to another general rate case. I hope we can invite organizations that have been involved in similar issues with other state commissions, such as the Electric Power Research Institute, Regulatory Assistance Project, solar and renewable industry associations, to help inform our discussions on rate design and the impact of conservation and distributed generation on the distribution grid.

320 In sum, I believe there are better ways for the Company to engage in a constructive dialogue with the Commission, our Staff, and the stakeholders, and move this dialogue forward. These are not easy issues to resolve and involve a complex balancing of a wide diversity of economic and public policy interests. I agree with the Majority that neither the Company's or Staff's proposals are ready for adoption in this case, but I do think they have played a useful role in enhancing our understanding. I do not necessarily think that a decoupling mechanism, however structured, is the preferred or default option for the Company at this time, and am open to consider any proposal in a better developed record that builds upon the dialogue in our Collaborative discussions.

PHILIP B. JONES, Commissioner

**APPENDIX A - CONTESTED ADJUSTMENTS
COMMISSION DETERMINATIONS**

	Adjustment	Net Operating Income	Rate Base	Revenue Requirement
	Actual Results of Operations	\$40,389,777	\$788,256,374	\$27,686,124
3.8	Schedule 300 Fee Change	-	-	-
4.3	Wage & Employee Benefits - <i>Pro Forma</i>	447,635	-	(722,516)
4.7	Insurance Expense	1,739,135	-	(2,807,094)
4.13	IHS Global Insight Escalation	-	-	-
5.1.1	Net Power Costs- <i>Pro forma</i>	(3,069,123)	-	4,953,793
6.2-6.2.2	Depreciation & Amortization Reserve to December 2013 Balance	-	-	-
6.3-6.3.2	Proposed Depreciation Rates-Expense	(886,437)	(886,437)	1,326,329
6.5	Retired Assets Depreciation Expense Removal	-	-	-
7.1	Interest True-up*	29,821	-	(48,133)
8.4	Major Plant Additions	(429,735)	18,429,412	2,865,115
8.10	Regulatory Asset Amortization	(1,950,000)	-	3,147,446
8.12-8.12.6	Adj. December 2013 AMA Plant Balances to December 2013 EOP Balances	-	-	-
9.1	Production Factor	(629,599)	142,456	1,033,006
	Sub-total Contested Adjustments	\$35,641,474	\$805,941,805	\$37,434,070
	Total Adjusted Results⁴²⁴	\$53,850,896	\$818,890,931	\$9,568,464

⁴²⁴ Sum of Appendix A (Sub-total Contested Adjustments) and Appendix B (Sub-total Uncontested Adjustments).

APPENDIX B – UNCONTESTED AJDUSTMENTS

	Adjustment	Net Operating Income	Rate Base	Revenue Requirement
	Actual Results of Operations			
3.1	Temperature Normalization	\$(3,700,295)		\$5,972,553
3.2	Revenue Normalization	(4, 827,929)		7,792,639
3.3	Effective Price Change	11,066,786		(17,862,619)
3.4	SO2 Emission Allowance Sales	481,474	(249,925)	(806,582)
3.5	Renewable Energy Credit and Renewable Energy Attribute Revenue	(1,464,670)		2,364,087
3.6	Wheeling Revenue	225,696		(364,290)
3.7	Ancillary Revenue	26,682		(43,357)
3.9	Wind Wake Loss Revenue	16,828		(27,161)
4.1	Miscellaneous General Expense	14,374		(23,201)
4.2	Wage & Employee Benefits - Restating	30,933		(49,928)
4.4	Irrigation Load Control Program	3,472		(5,604)
4.5	Remove Non-recurring Entries	(101,034)		163,076
4.6	DSM Revenue and Expense Removal	6,923,690		(11,175,352)
4.8	Advertising Expense	261		(421)
4.9	Memberships & Subscriptions	(973)		1,570
4.10	Uncollectible Expense	(274,576)		443,186
4.11	Legal Expenses	(60,982)		98,430
4.12	Collection Agency Fees	-	-	-
5.1	Net Power Costs - Restating	7,484,568		(12,080,652)
5.2	James River Royalty Offset	441,934		(713,315)
5.3	Colstrip 3 Removal	314,398	(8,567,345)	(1,516,931)

6.1	Hydro Decommissioning	(3,781)	(212,765)	(18,966)
6.4	Vehicle Depreciation Study	74,724	(143,764)	(137,549)
7.2	Property Tax Expense	(70,366)	-	113,576
7.3	Renewable Energy Tax Credit	661,917	-	(1,068,383)
7.4	Power Tax ADIT Balance	-	(1,637,024)	(192,886)
7.5	Washington Low Income Tax Credit	(25,873)	-	41,761
7.6- 7.6.1	Flow-through Adjustment	407,649	(9,662,969)	(1,796,539)
7.7	Remove Deferred State Tax Expense and Balance	488,064	244,032	(759,018)
7.8	WA Public Utility Tax	524,708	-	(846,919)
8.1	Jim Bridger Mine Rate Base	(138,615)	26,734,872	3,373,837
8.2	Environmental Remediation	(171,517)	(250,034)	247,380
8.3	Customer Advances for Construction	-	(481,414)	(56,724)
8.5- 8.5.1	Miscellaneous Rate Base	-	(20,135,895)	(2,372,561)
8.6	Powerdale Hydro Removal	(58,361)	97,700	105,710
8.7	Removal of Colstrip 4 AFUDC	17,991	(360,049)	(71,462)
8.8	Trojan Unrecovered Plant Adjustment	(99,762)	(83,643)	151,168
8.9	Customer Service Deposits	(2,710)	(3,361,134)	(391,659)
8.11	Misc. Asset Sales & Removals	4,540	-	(7,328)
8.13	Investor Supplied Working Capital	-	31,018,483	3,654,829
	Sub-total Uncontested Adjustments	\$18,209,423	\$12,949,127	\$(27,865,606)

APPENDIX C - CONSOLIDATED DOCKETS

DETERMINATIONS IN DOCKETS

**UE-131384 (COLSTRIP DEFERRAL),
UE-132350 (DEPRECIATION DEFERRAL),
UE-140094 (HYDRO DEFERRAL),
and
UE-140617 (MERWIN FISH COLLECTOR PROJECT DEFERRAL)**

Cost Deferrals	Allowed Amounts to Amortize in Schedule 92
Colstrip Deferral (UE-131384)	\$0.00
Depreciation Deferral (UE-132350)	(\$877,345)
Hydro Deferral (UE-140094)	\$0.00
Merwin Fish Collector Project Deferral (UE-140617)	\$529,312
TOTAL	(\$348,033)